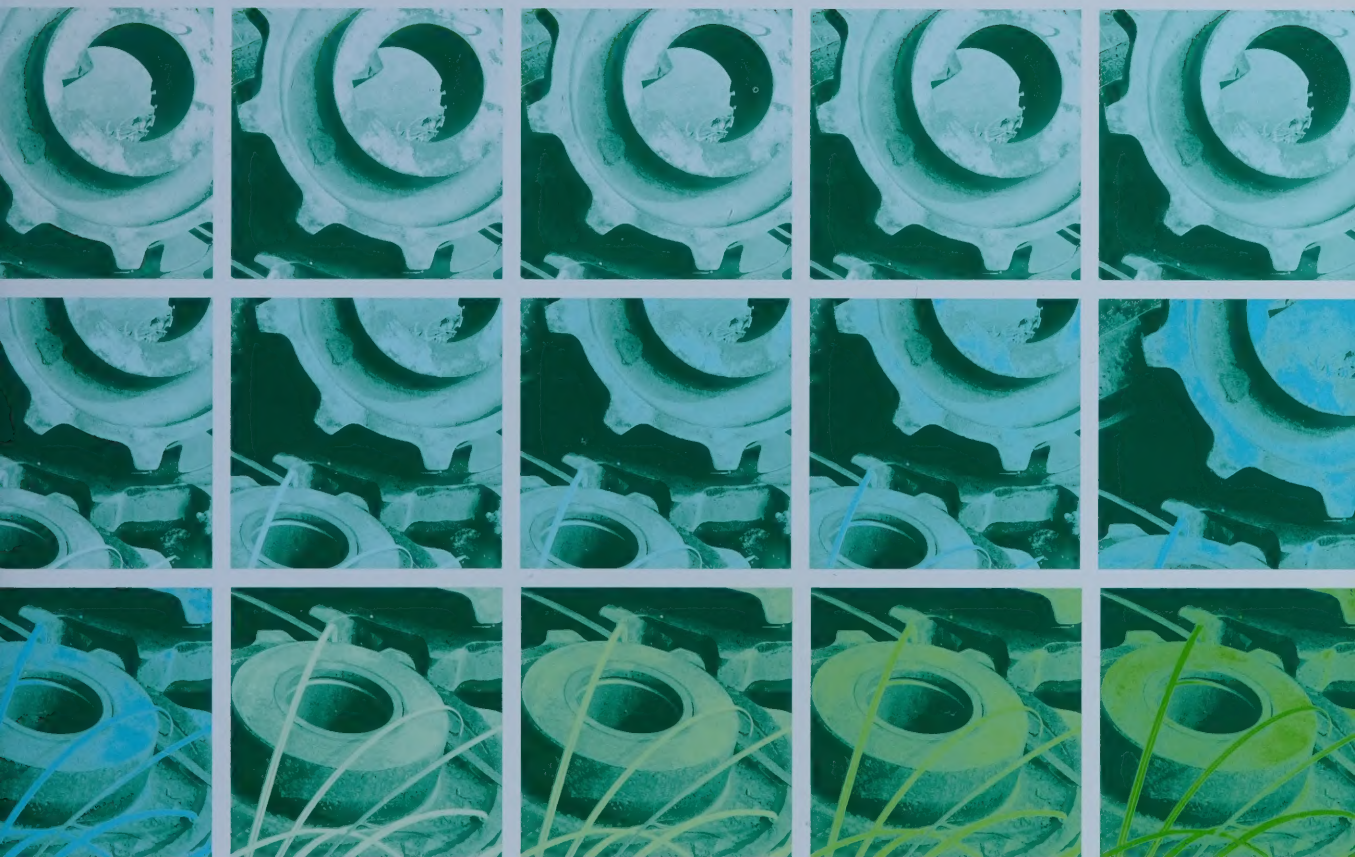


MOVING FORWARD



PACIFIC NORTHERN GAS LTD. DELIVERS NATURAL GAS TO CUSTOMERS IN WEST-CENTRAL BRITISH COLUMBIA AND THROUGH ITS SUBSIDIARY, PACIFIC NORTHERN GAS (N.E.) LTD., TO CUSTOMERS IN THE PROVINCE'S NORTHEAST.

PACIFIC NORTHERN'S TRANSMISSION PIPELINE IS CONNECTED TO THE DUKE ENERGY SYSTEM NEAR SUMMIT LAKE, BRITISH COLUMBIA AND EXTENDS 587 KILOMETERS TO THE WEST COAST. SERVICE IS PROVIDED TO APPROXIMATELY 23 THOUSAND CUSTOMERS INCLUDING A NUMBER OF LARGE INDUSTRIAL OPERATIONS. IN ADDITION, PROPANE VAPOUR DISTRIBUTION IS PROVIDED IN THE COMMUNITY OF GRANISLE.

PACIFIC NORTHERN GAS (N.E.) SYSTEMS SERVE APPROXIMATELY 16 THOUSAND CUSTOMERS IN THE FORT ST. JOHN, DAWSON CREEK AND TUMBLER RIDGE AREAS. GAS SUPPLY IS RECEIVED AT A NUMBER OF LOCATIONS WITHIN THE FORT ST. JOHN SERVICE AREA. IN THE DAWSON CREEK AREA THE COMPANY'S TRANSMISSION PIPELINE IS USED TO TRANSPORT GAS FROM THE DUKE ENERGY SYSTEM. IN TUMBLER RIDGE THE COMPANY OPERATES ITS OWN GAS PROCESSING PLANT.

PACIFIC NORTHERN'S HEAD OFFICE IS LOCATED IN VANCOUVER, BRITISH COLUMBIA. CUSTOMER CARE AND ADMINISTRATIVE FUNCTIONS ARE SUPPORTED FROM A REGIONAL CENTRE IN TERRACE. IN ADDITION, PERSONNEL RESPONSIBLE FOR CUSTOMER SERVICE AND SYSTEM CONSTRUCTION, OPERATION AND MAINTENANCE ARE STATIONED IN NINE COMMUNITIES LOCATED WITHIN THE COMPANY'S SERVICE AREA.





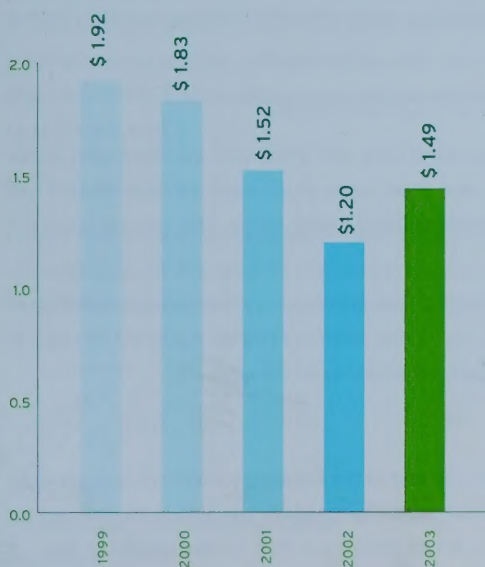
COMPARATIVE FINANCIAL HIGHLIGHTS

	2003	2002	2001	2000	1999
TOTAL ENERGY DELIVERED (TJ)	36 638	39 463	31 781	34 771	42 577
NET INCOME (000)	\$ 5,668	\$ 4,590	\$ 5,715	\$ 6,838	\$ 7,125
EARNINGS PER COMMON SHARE	\$ 1.49	\$ 1.20	\$ 1.52	\$ 1.83	\$ 1.92
DIVIDENDS PAID PER COMMON SHARE	\$ 3.55	\$ 0.00	\$ 0.00	\$ 0.56	\$ 1.12
TOTAL INVESTMENT IN UTILITY PLANT (000)	\$ 174,348	\$ 177,314	\$ 179,301	\$ 183,351	\$ 182,917

BUSINESS HIGHLIGHTS

- Pacific Northern's **net income was \$5.7 million** in 2003, compared with \$4.6 million in 2002.
- After providing for preferred share dividends, **earnings per common share were \$1.49** in 2003 compared with \$1.20 in 2002.
- Common share dividends of \$3.55** were paid in 2003, which included a special dividend of \$2.75 per share paid in January 2003. Dividends on the common shares were reinstated in March 2003 at \$0.20 per share per quarter. Quarterly dividends on the common shares had not been paid since June 2000.
- Gas deliveries during the year totalled **36.6 petajoules**, compared with 39.5 petajoules in 2002.
- Additions to property, plant and equipment totalled \$5.4 million** in 2003, compared with \$6.0 million in 2002.

EARNINGS PER COMMON SHARE



REPORT TO SHAREHOLDERS



Pacific Northern Gas experienced an eventful, largely positive, year in 2003. We further stabilized the Company's financial position by negotiating a new operating line of credit and establishing an improved gas commodity hedging program. The British Columbia Utilities Commission (the "Commission") approved a rate stabilization adjustment mechanism for residential and small commercial customers that reduces risk related to forecasting customer deliveries. We have a new major shareholder who brings expertise that will be valuable as we move forward. Finally, we initiated a strategic planning process that could see the Company convert to an income trust ownership structure - a move we see as being key to the Company's long-term prospects and growth. In

February 2004, the Company was pleased to sign a memorandum of agreement with a major customer, West Fraser Mills Ltd., for a new 10-year transportation contract. This contract is subject to approval by the Commission.

IMPROVED FINANCIAL PERFORMANCE & STABILITY

Net income in 2003 was significantly improved at \$5.7 million compared to \$4.6 million in 2002. The Company paid a special dividend of \$2.75 per common share and commenced a regular quarterly dividend of \$0.20 per share.

We were also pleased when Dominion Bond Rating Service (DBRS) made its decision in November to raise the ratings on the Company's secured debentures from BB(high) to BBB(low). In announcing the upgrade, DBRS noted three factors important to its decision:

- (i) the Company's medium-term contract signed in 2002 with Methanex Corporation, its largest customer;
- (ii) positive developments in the Company's regulatory framework including Commission approval of a rate stabilization adjustment mechanism that protects the Company against variances between actual and forecast deliveries to residential and small commercial customers; and,
- (iii) the Company's new \$25-million operating line of credit that provides it with additional financial flexibility both through increased liquidity at a lower cost and access to a hedging line, which allows the Company to better manage gas price volatility.

NATURAL GAS SUPPLY AND MARKET AREA CONDITIONS

Gas commodity prices continued to be extremely volatile in 2003. In the early part of the year, gas commodity prices reached historically high levels before trending down later in the year. Given these experiences, we determined it was prudent to fix prices for the majority of its gas supply for the 2003 to 2004 winter period. This strategy has been successful in managing gas price volatility over the winter.

Unfortunately, the economy continues to remain weak in the Western system area resulting in a lower consumption of gas by many customers. However, the economy in the Northeast service area continues to grow due to the strength of the oil and gas exploration sector, which is reflected in our new customer additions in that area.

MAJOR PIPELINE SERVICE DISRUPTION

On November 28, 2003, a massive debris slide severed about one kilometer of the Company's eight-inch high-pressure transmission pipeline 55 kilometers east of Prince Rupert, British Columbia. The Company was able to maintain partial gas service to the hospital and hotels. Full service was restored to Prince Rupert and Port Edward within ten days - a

REPORT TO SHAREHOLDERS

remarkable achievement given that the slide occurred in an extremely remote, difficult to access area. In a letter to the Company, the mayor of Prince Rupert, Mayor Herb Pond, expressed the City's thanks for reconnecting the pipeline in such a short period of time: "Flying over the site and seeing the pictures of the slide via the media was graphic evidence to everyone of the gargantuan job that the repair work entailed." All of the Company's employees are to be commended for their ingenuity in promptly and safely repairing the pipeline under such extreme circumstances. We also appreciated our customers' patience during this service disruption.

NEW MAJOR SHAREHOLDER

We are pleased to have Tricor Acquisition (STP) Inc., a subsidiary of Tricor Pacific Capital, Inc., as our new major shareholder. Tricor is a private equity investment company with its head office in Vancouver.

Shareholders of Class A common shares became entitled to vote when the Company's two classes of common shares were redesignated to a single class. This occurred on December 18, 2003 with the sale of Duke Energy Gas Transmission's 40 percent interest in the Company to Tricor.

With Tricor's three principals now appointed to the Company's Board of Directors, we are very excited to have access to their entrepreneurial insight.

OUTLOOK

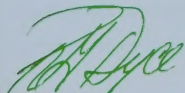
Moving forward, we feel optimistic that the decisions we have made in 2003 have laid the foundation for further opportunities to succeed in 2004.

We remain hopeful that an agreement on the softwood lumber dispute can be reached that will be positive for sawmill operators in the Company's service areas. The Company also continues to be encouraged by efforts of the British Columbia Provincial Government to have the moratorium lifted on oil and gas exploration off the Pacific Coast.

Our application seeking approval to convert to an income trust ownership structure that was filed with the Commission in January 2004 will be reviewed in a public hearing process. A decision by the Commission is expected by mid-2004. If the decision is positive, with our shareholders' approval, the Company expects to be converted to an income trust by the end of 2004. This new structure would allow the Company to pursue growth and diversification strategies beneficial to all stakeholders.

WITH THANKS

I would like to thank the Company's Board of Directors for their support during 2003, in particular, around the many challenging issues that arose as the Company pursued strategic options to increase shareholder value. Lastly, I extend my heartfelt appreciation for the extraordinary efforts of all our employees during the year.



Roy G. Dyce
President and Chief Executive Officer
February 27, 2004

REPORT FROM THE CHAIR



The Board of Pacific Northern Gas continues to strive for excellence in representing the shareholders of the Company. The Board's governance practices are reviewed regularly and changes are adopted as required to ensure shareholders benefit from best practices. The full details of the Company's governance practices, as they compare to the guidelines issued by the Toronto Stock Exchange, are found in the Statement of Corporate Governance following this report.

The Company instituted a number of changes in 2003 that demonstrate its commitment to adopting best practices:

- Upon Duke Energy Corporation's disposition of its control position and the consolidation of the Company's two-class common share structure into one class with each share carrying the right to one vote, the size of the Board was increased to eight directors and all but one director are now unrelated to the Company;
- At the time the size of the Board was increased, each Committee was restructured to ensure it was comprised solely of unrelated directors and representatives on the Audit Committee were chosen to ensure the highest degree of financial literacy; and,
- The Board formed a Special Committee in late 2002 that engaged a financial advisor in early 2003 to review options available to the Company to enhance shareholder value. This led to the development of plans to facilitate the change to a one-class/one-vote common share structure and for the potential conversion of the Company to an income trust ownership structure.

In addition to regular quarterly Board of Director meetings, director stewardship of the Company during the past year was managed by five additional Committees of the Board. A total of 30 meetings were held during the year of which 23 were Committee meetings, each of which consisted of three members of the Board, and seven were both regular or special meetings of the full Board of Directors. The Special Committee of the Board that was constituted to address matters related to the disposition of Duke Energy's interest in the Company and to review shareholder strategic value options was the most active Committee with 11 meetings during the year. Overall attendance by directors at both Board and Committee meetings was 94 percent. This excellent record of attendance for the Company's directors demonstrates the high level of commitment that the directors have to fulfilling their responsibilities to shareholders.

The past year produced many challenges that have largely been successfully overcome by the Company's employees. On behalf of all my fellow directors, I extend my thanks and appreciation to the management team and to all of the Company's employees who made it easier for us to perform our task of stewardship.

One of our long-term directors, Robert F. O'Shaughnessy, retired from the Board in December 2003. Bob was associated with the Company for just over 30 years. He was appointed to the Board in 1976 and served as President of the Company until his retirement in 1994. On behalf of the Board, I thank Bob for his many years of valuable service. I would also like to welcome to the Board Roderick R. Senft, J. Trevor Johnstone and David J. Rowntree.

A handwritten signature in blue ink, appearing to read "R. Chase".

Robert F. Chase
Chair of the Board
February 27, 2004

CORPORATE GOVERNANCE REPORT

The Toronto Stock Exchange ("TSX") requires that the Company disclose annually the corporate governance practices of its Board of Directors ("Board"). Through its Corporate Governance Committee, the Board administers a program to develop and sustain suitable and effective processes and structures to guide the direction and management of the business and affairs of the Company in the pursuit of enhanced corporate performance and shareholder value. The following report addresses how the Company fulfills the principal responsibilities of a board of directors contained in the guidelines for corporate governance established by the TSX. The Company considers itself to be in compliance with the guidelines.

Prior to December 18, 2003, Duke Energy Corporation, through its subsidiary Westcoast Energy Inc. ("Westcoast"), owned approximately 40 percent of the non-voting participating equity in the Company and 100 percent of the voting equity. Westcoast was a significant shareholder of the Company, with 100 percent voting control. On December 18, 2003, Westcoast sold 100 percent of its interest in the Company to Tricor Acquisition (STP) Inc. ("Tricor"). Immediately prior to the sale, the Company's non-voting participating equity and its voting, participating equity were consolidated into one class of voting common shares. As a result, Tricor now holds approximately 37 percent of the common shares of the Company and does not have the ability to elect a majority of the Board. "Significant shareholder" is defined by the TSX as a shareholder with the ability to elect a majority of the Board. The Company does not have a significant shareholder.

1 STEWARDSHIP OF THE COMPANY

THE BOARD OF DIRECTORS OF EVERY CORPORATION SHOULD EXPLICITLY ASSUME RESPONSIBILITY FOR THE STEWARDSHIP OF THE CORPORATION AND, AS PART OF THE OVERALL STEWARDSHIP RESPONSIBILITY, SHOULD ASSUME RESPONSIBILITY FOR THE FOLLOWING MATTERS:

The Board, as set out in its terms of reference, has the responsibility for overseeing the conduct of the business of the Company and the activities of management in carrying out its responsibility for the day-to-day operations of the business. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Company meets its obligations on an ongoing basis in an efficient and reliable manner. The Board approves all significant decisions affecting the Company and reviews the results of such decisions.

The Board operates by seeking the advice of and delegating powers, duties and responsibilities to committees of the Board, by delegating certain authorities to management and by reserving certain powers to itself. Members of the management team report to the Board and its committees on a regular basis to review the Company's financial and operational results and the Company's progress in fulfilling its strategic goals and objectives.

In addition to those matters which must by law be approved by the Board, the Board retains the responsibility for managing its own affairs including selecting its Chair, nominating candidates for election to the Board, constituting committees of the Board and determining director compensation. The Company has adopted a code of corporate conduct, which has been communicated to all employees.

CORPORATE GOVERNANCE REPORT

A STRATEGIC PLANNING PROCESS

The Board ensures that goals and a strategic planning process are in place for the Company and that systems have been developed to monitor and manage the principal risks and returns associated with the Company's business activities. The Board discusses and reviews all materials related to the Company's strategic plan with management, and is responsible for approving the strategic plan. The Board works with management to develop an appropriate planning cycle and strategic objectives, based on the circumstances faced by the Company. The Board receives regular updates from management on the Company's progress in meeting its strategic objectives.

B PRINCIPAL RISKS

The Board, through the Audit Committee, is responsible for identifying and reviewing the Company's principal business risks, ensuring that the systems in place are effective to manage those risks and developing policies for risk management. The Audit Committee meets quarterly to review financial reports and discuss significant risk areas with the external auditors and management.

C SUCCESSION PLANNING

The Board, through the Human Resources and Compensation Committee, is responsible for succession planning, performance evaluation and setting compensation for the President and Chief Executive Officer. The President advises the Committee on issues relating to succession planning and performance for the senior management team. The President also advises and seeks guidance from the Committee on matters relating to the development and training of senior management personnel.

D COMMUNICATIONS POLICY

The Board approves all of the Company's major communications, including annual and quarterly reports, financing documents and earnings releases. The Company has adopted a disclosure policy that establishes procedures to provide the public with broad disclosure on a timely basis of material information concerning the affairs of the Company and communications with analysts. The Company's practices encourage the free flow of accurate and appropriate communication and, at the same time, discourage selective disclosure of material information that has not been publicly disclosed.

The Company maintains an active shareholder relations program. The program is designed to ensure that shareholder inquiries receive a prompt response from an appropriate officer of the Company. Information about the Company is also available on the Company's website at www.png.ca. The website is updated regularly and permits access to interim and annual reports, press releases and other information about the Company.

E INTEGRITY OF INTERNAL CONTROL

The Board, through the Audit Committee, is responsible for ensuring that the Company's management has designed and implemented an effective system of internal controls and for reviewing and reporting on the integrity of the consolidated financial statements of the Company. This Committee also receives any recommendations from the external auditors and management on internal controls.

CORPORATE GOVERNANCE REPORT

2 BOARD INDEPENDENCE

A MAJORITY OF THE DIRECTORS SHOULD BE "UNRELATED".

The Board reviews the relationships of the directors with the Company to determine whether they are related or unrelated. In making this determination, the Board polls each director as to the nature and extent of each director's relationship with the Company and considers any other information brought forward by management. The Board is composed of eight directors, one of whom, the President and Chief Executive Officer, is a full-time officer of the Company. The Board has determined that the rest of the directors are unrelated. The Company does not have a significant shareholder. In addition, no member of management sits on any of the Board Committees.

3 INDIVIDUAL UNRELATED DIRECTORS

THE BOARD HAS RESPONSIBILITY FOR APPLYING THE DEFINITION OF "UNRELATED" DIRECTOR TO EACH INDIVIDUAL DIRECTOR AND FOR DISCLOSING ANNUALLY THE ANALYSIS OF THE APPLICATION OF THE PRINCIPLES SUPPORTING THIS DEFINITION AND WHETHER THE BOARD HAS A MAJORITY OF UNRELATED DIRECTORS.

The President and Chief Executive Officer is an inside director. The remaining directors do not have interests in or relationships with the Company (other than interests and relationships arising from shareholdings), which could, or could reasonably be perceived to, materially interfere with such directors' ability to act with a view to the best interests of the Company. The Board has concluded that seven of the eight directors of the Company are unrelated.

4 NOMINATING COMMITTEE

THE BOARD SHOULD APPOINT A COMMITTEE OF DIRECTORS COMPOSED EXCLUSIVELY OF OUTSIDE (I.E., NON-MANAGEMENT) DIRECTORS, A MAJORITY OF WHOM ARE "UNRELATED" DIRECTORS, WITH RESPONSIBILITY FOR PROPOSING NEW NOMINEES TO THE BOARD AND FOR ASSESSING DIRECTORS ON AN ONGOING BASIS.

The Company does not have a nominating committee. The Corporate Governance Committee, which has primary responsibility for the search for and recommendation of new candidates for election to the Board, seeks to select well-qualified candidates with a diversity of background, experience and geographic location to maintain a well-balanced and highly competent group of directors with the ability to act together effectively. This Committee is also responsible for the ongoing assessment of directors. All members of the Corporate Governance Committee are unrelated.

5 ASSESSING THE BOARD'S EFFECTIVENESS

THE BOARD SHOULD IMPLEMENT A PROCESS TO BE CARRIED OUT BY THE NOMINATING COMMITTEE OR OTHER APPROPRIATE COMMITTEE FOR ASSESSING THE EFFECTIVENESS OF THE BOARD AS A WHOLE, THE COMMITTEES OF THE BOARD AND THE CONTRIBUTION OF INDIVIDUAL DIRECTORS.

CORPORATE GOVERNANCE REPORT

Through the auspices of the Corporate Governance Committee, an assessment of the overall effectiveness of the Board is conducted annually. The Chair reviews the activities of the Board and the Committees over the prior year, including the attendance record of each Board member, and discusses pertinent issues with each Board member as deemed appropriate. This assessment is tabled and reviewed by the Corporate Governance Committee.

The Board met seven times in 2003, with 93 percent attendance by directors.

6 ORIENTATION AND EDUCATION OF DIRECTORS

THE COMPANY SHOULD PROVIDE AN ORIENTATION AND EDUCATION PROGRAM FOR NEW RECRUITS TO THE BOARD.

All new directors receive a Board manual containing public information about the Company, as well as the terms of reference and timetables for the Board and the committees and other relevant corporate and business information. The senior management team makes regular presentations to the Board on matters with significant impact on the Company's business.

7 EFFECTIVE BOARD SIZE

THE BOARD SHOULD EXAMINE ITS SIZE AND, WITH A VIEW TO DETERMINING THE IMPACT OF THE NUMBER UPON EFFECTIVENESS, UNDERTAKE WHERE APPROPRIATE A PROGRAM TO REDUCE THE NUMBER OF DIRECTORS TO A NUMBER WHICH FACILITATES MORE EFFECTIVE DECISION-MAKING.

The Board regularly reviews its composition and size to ensure that the Company is in compliance with applicable legislative requirements and that the composition and size of the Board fairly reflects the interests of all shareholders. In 2003, the size of the Board was increased by one director, to a total of eight. The current composition and size of the Board is considered appropriate to permit the directors to efficiently and effectively fulfill their fiduciary obligations.

8 COMPENSATION OF DIRECTORS

THE BOARD OF DIRECTORS SHOULD REVIEW THE ADEQUACY AND FORM OF THE COMPENSATION OF DIRECTORS AND ENSURE THE COMPENSATION REALISTICALLY REFLECTS THE RESPONSIBILITIES AND RISK INVOLVED IN BEING AN EFFECTIVE DIRECTOR.

Directors are compensated through annual retainer fees and a fee per meeting attended, as well as reimbursement for expenses. The Board, through the Human Resources and Compensation Committee, is responsible for periodically reviewing the adequacy and form of compensation of directors and for ensuring that compensation realistically reflects the responsibilities and risks involved in being an effective director of the Company and for reporting and making recommendations to the Board accordingly. Periodically outside advisors are engaged to review the adequacy of directors' compensation, with the last review conducted in 2002.

CORPORATE GOVERNANCE REPORT

9

COMMITTEES AND OUTSIDE DIRECTORS

COMMITTEES OF THE BOARD OF DIRECTORS SHOULD GENERALLY BE COMPOSED OF OUTSIDE DIRECTORS, A MAJORITY OF WHOM ARE UNRELATED DIRECTORS, ALTHOUGH SOME BOARD COMMITTEES (SUCH AS THE EXECUTIVE COMMITTEE) MAY INCLUDE ONE OR MORE INSIDE DIRECTORS.

The Board has established and adopted terms of reference and annual timetables for five committees:

- Audit Committee
- Executive Committee
- Environment, Health and Safety Committee
- Human Resources and Compensation Committee
- Corporate Governance Committee

All committees are composed entirely of outside and unrelated directors. See guideline 13 for a discussion of the role of the Audit Committee.

The Executive Committee is composed of three directors and is narrowly mandated to act as the approving body for expenditures which have been broadly approved by the Board and which are beyond the approval levels of the President and Chief Executive Officer and to perform such functions and exercise such powers as are specifically delegated to the committee by the Board. This Committee met twice in 2003, with 83 percent attendance by committee members.

The Environment, Health and Safety Committee is composed of three directors, and is responsible for reviewing and monitoring the policies and activities of the Company relating to environment, health and safety matters on behalf of the Board. This Committee met twice in 2003, with full attendance by all members for each meeting.

The Human Resources and Compensation Committee is composed of three directors, and is generally responsible for recommending to the Board human resources and compensation policies and guidelines for application to the Company and for implementing and overseeing human resources and compensation policies approved by the Board. This Committee met twice in 2003, with full attendance by all members for each meeting.

The Corporate Governance Committee is composed of three directors. Through the Corporate Governance Committee, the Board develops sound corporate governance practices to enhance corporate performance. This Committee has responsibility for proposing new members to the Board, establishing criteria for Board membership, recommending composition of the Board and its committees, assessing directors' and Board performance on an ongoing basis, and ensuring an orientation and education program is in place for new members of the Board. This Committee met twice in 2003, with full attendance by all members for each meeting.

Special Committees of the Board are struck from time to time to deal with matters of significance before the Company. During 2003, a Special Committee to the Board, which was formed in November, 2002 to consider options to enhance shareholder value, met 11 times, with 94 percent attendance by committee members. This Committee was disbanded in December, 2003.

CORPORATE GOVERNANCE REPORT

10 APPROACH TO CORPORATE GOVERNANCE

EVERY BOARD OF DIRECTORS SHOULD EXPRESSLY ASSUME RESPONSIBILITY FOR, OR ASSIGN TO A COMMITTEE OF DIRECTORS, THE GENERAL RESPONSIBILITY FOR DEVELOPING THE CORPORATION'S APPROACH TO GOVERNANCE ISSUES. THIS COMMITTEE WOULD BE RESPONSIBLE FOR THE CORPORATION'S RESPONSE TO THESE GOVERNANCE GUIDELINES.

The prime responsibility of the Corporate Governance Committee is to develop and monitor the Company's overall approach to corporate governance issues and to administer a corporate governance system which is effective in the discharge of the Company's obligations to its stakeholders, including providing timely, accurate and full disclosure. The Corporate Governance Committee has responsibility for reviewing and approving the Company's Statement of Corporate Governance. Management and the external auditors provide the Board with updates on governance initiatives by regulators as well as best practices recommendations on a regular basis.

11 POSITION DESCRIPTIONS

THE BOARD OF DIRECTORS, TOGETHER WITH THE CHIEF EXECUTIVE OFFICER, SHOULD DEVELOP POSITION DESCRIPTIONS FOR THE BOARD AND FOR THE CHIEF EXECUTIVE OFFICER, INVOLVING THE DEFINITION OF THE LIMITS TO MANAGEMENT'S RESPONSIBILITIES. IN ADDITION, THE BOARD SHOULD APPROVE OR DEVELOP THE CORPORATE OBJECTIVES, WHICH THE CHIEF EXECUTIVE OFFICER IS RESPONSIBLE FOR MEETING.

Terms of reference for the Board and position descriptions for the Chair and the President and Chief Executive Officer have been approved by the Board.

The goals and objectives for the President and Chief Executive Officer are drafted by the President and reviewed and discussed with the Human Resources and Compensation Committee prior to being presented to the full Board for acceptance.

The Board primarily expects management to review the Company's strategies and their implementation, carry out a comprehensive budgeting process and monitor financial performance against the budget, and identify opportunities and risks affecting the Company's business and develop strategies to address those challenges.

12 BOARD INDEPENDENCE

THE BOARD SHOULD IMPLEMENT STRUCTURES AND PROCEDURES WHICH ENSURE THAT IT CAN FUNCTION INDEPENDENTLY OF MANAGEMENT.

The Board acts independently of management either directly or through committees of the Board which are delegated some of the Board's responsibilities. The Chair of the Board is an unrelated director. At each meeting of the directors, the outside directors meet in-camera without members of management present.

CORPORATE GOVERNANCE REPORT

13 AUDIT COMMITTEE

THE AUDIT COMMITTEE SHOULD BE COMPOSED OF ONLY UNRELATED DIRECTORS. THE ROLES AND RESPONSIBILITIES OF THE AUDIT COMMITTEE SHOULD BE SPECIFICALLY DEFINED SO AS TO PROVIDE APPROPRIATE GUIDANCE TO AUDIT COMMITTEE MEMBERS AS TO THEIR DUTIES. THE AUDIT COMMITTEE SHOULD HAVE DIRECT COMMUNICATION CHANNELS WITH THE INTERNAL AND EXTERNAL AUDITORS TO DISCUSS AND REVIEW SPECIFIC ISSUES AS APPROPRIATE.

The Audit Committee is composed entirely of unrelated directors. Two of the members are financial professionals and all members are financially literate. The Committee's responsibilities are set out in its terms of reference. Its responsibilities include ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts and reviewing the appropriateness and effectiveness of the Company's policies and business practices that impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems, financial controls, management reporting and risk management. The Audit Committee reviews the Company's annual and interim reports and the annual information form as well as the annual audit plan and the results of the audit. At each meeting of the Audit Committee, members of the committee meet in-camera with the external auditors without management present. The Audit Committee met four times in 2003, with 92 percent attendance by committee members.

14 OUTSIDE ADVISORS

THE BOARD SHOULD IMPLEMENT A SYSTEM TO ENABLE AN INDIVIDUAL DIRECTOR TO ENGAGE AN OUTSIDE ADVISOR AT THE COMPANY'S EXPENSE IN APPROPRIATE CIRCUMSTANCES. THE ENGAGEMENT OF THE OUTSIDE ADVISOR SHOULD BE SUBJECT TO THE APPROVAL OF AN APPROPRIATE COMMITTEE OF THE BOARD.

Directors and committees of the Board are permitted to hire outside advisors at the expense of the Company with the approval of the Board. Outside advisors, lawyers and financial advisors were hired in 2003 by a Special Committee of the Board to review options to enhance shareholder value. In addition, a human resources consulting firm was engaged by the Board in 2002 to review and assess director compensation.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

FORWARD-LOOKING STATEMENTS

Management's discussion and analysis contains certain forward-looking statements that are subject to risks and uncertainties that may cause the results or events predicted in this discussion to differ materially from actual results or events. In addition to the risks outlined in the Risk Management section at the end of the discussion, factors which could cause the results or events to differ include, but are not limited to: general economic conditions; gas commodity price volatility; decisions by regulators; seasonal weather patterns; the cost and availability of capital; and, the ability of the Company to attract and retain quality employees. No assurance can be given that results, performance or achievement expressed in, or implied by, forward-looking statements within this disclosure will occur, or if they do, that any benefits may be derived from them. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

CORPORATE PERFORMANCE AND STRATEGY

The Company's financial results showed marked improvement in 2003 relative to 2002. These results, along with the Company's pursuit of alternatives to increase shareholder value, are reflected in the total return to shareholders in 2003 of 36 percent, comprised of share price increases plus dividends, assuming dividend reinvestment. However, the 2003 results do not yet, in management's opinion, reflect appropriate levels of return on capital employed. As discussed in greater detail in the section on capital structure on page 24, the Company continues to have greater equity on its balance sheet than the regulator recognizes for the purposes of determining customer rates. Certain elements of the strategy to improve shareholder value, including elimination of the voting/non-voting common share structure, were implemented in 2003 and progress was made on another key aspect of the strategy, that being to recapitalize the Company under an income trust ownership structure. Costs incurred in 2003 to pursue the strategy were \$0.6 million after tax.

Upon successful conversion to an income trust, the Company expects it would have improved access to capital. It intends to utilize this enhanced access to capital to pursue growth and diversification strategies that will benefit both shareholders and customers through accretive investments that reduce the Company's dependency on its small number of large industrial customers.

OVERALL CORPORATE RESULTS

The Company's consolidated results for 2003 and 2002 are as follows:

Dollar amounts in thousands, except per share and per GJ figures	Q4 2003	Q4 2002	% Change	2003	2002	% Change
Deliveries (TJ)						
Sales	2 549	2 458	3.7%	7 754	8 045	(3.6%)
Transportation Service	7 541	8 197	(8.0%)	28 884	31 418	(8.1%)
Total	10 090	10 655	(5.3%)	36 638	39 463	(7.2%)
Customers at period end	39,106	39,254	(0.4%)	39,106	39,254	(0.4%)
Weighted Average cost of gas purchased (\$ per GJ)	5.62	5.06	11.1%	6.59	4.11	60.3%
Operating revenues	39,448	32,889	19.9%	133,727	109,063	22.6%
Operating margin, consisting of						
Operating revenues less						
Cost of sales	14,640	13,584	7.8%	49,310	52,234	(5.6%)
Income before income taxes	4,514	4,281	5.4%	10,428	11,525	(9.5%)
Net income	2,623	1,270	106.5%	5,668	4,590	23.5%
Operating cash flow	4,862	4,033	20.6%	14,153	14,570	(2.9%)
Basic earnings per common share	0.71	0.34	108.8%	1.49	1.20	24.2%
Dividends paid per common share	0.20	0	N/A	3.55	0	N/A

MD&A

MANAGEMENT'S EXPLANATION OF RESULTS

Net income for 2003 was \$5.7 million, compared with \$4.6 million for 2002, or an increase of 24 percent. After providing for preferred share dividends, earnings per common share for 2003 were \$1.49 compared with \$1.20 for 2002. Deliveries to residential and commercial customers in 2003 were lower by 0.1 petajoules, or 1.4 percent, compared to deliveries in 2002. Some of the reduction in deliveries was due to weather, which was approximately one percent warmer in 2003 than in 2002. Deliveries to residential and commercial customers in 2002 were lower by 0.8 petajoules, or 10 percent, compared to the forecast volumes used by the Company's regulator to set customer rates, negatively impacting 2002 net income by \$1.9 million. In 2003, deliveries were 1.2 percent lower than the forecast volumes used to set rates. The reduction in deliveries did not significantly impact net income due to the existence of a deferral account that captured the after-tax value of the revenue variance, amounting to \$0.9 million, arising from differences between actual and forecast volumes for residential and commercial customers. Net income in 2003 was also negatively impacted by \$0.6 million relating to increased administrative costs incurred in pursuing options to enhance shareholder value.

Operating revenues in 2003 increased to \$133.7 million as compared with \$109.1 million in 2002, largely due to the increase in the commodity cost of natural gas that is passed through to customers without markup as well as an increase of \$14.6 million in sales of gas surplus to the needs of the Company's sales customers ("off system gas sales").

Operating margin in 2003 decreased to \$49.3 million, as compared with \$52.2 million in 2002. This decrease was due to reductions in customer rates in 2003 that were based on anticipated reductions in amortization and company use gas expenses.

FOURTH QUARTER RESULTS

Net income for the quarter ended December 31, 2003 was \$2.6 million, compared with net income of \$1.3 million for the quarter ended December 31, 2002. After providing for preferred share dividends, earnings per common share in the fourth quarter were \$0.71 compared with earnings per common share of \$0.34 share in the corresponding period in 2002. The increase in net income in the fourth quarter is primarily due to weather that was approximately 10 percent colder than in 2002, resulting in a 7 percent increase in deliveries to residential and commercial customers compared to the same period in 2002.

Operating revenues in the fourth quarter of 2003 increased to \$39.4 million as compared with \$32.9 million in the same period in 2002. The increase in operating revenue in the fourth quarter is attributed to revenues from residential and commercial customers being \$7.2 million higher, due to the higher commodity cost of gas and increased sales volumes, as well as an increase of \$0.8 million in revenue from off-system gas sales. These increases were offset by a reduction of \$1.4 million in sales to industrial customers, compared to the corresponding period in 2002.

Operating margin in the fourth quarter of 2003 increased to \$14.6 million, as compared with \$13.6 million in the corresponding period in 2002, due to higher customer deliveries in the quarter.

SELECTED CONSOLIDATED QUARTERLY RESULTS (UNAUDITED)

(\$ in thousands, except per share data)

2003

	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	\$ 41,683	\$ 28,571	\$ 24,025	\$ 39,448	\$ 133,727
Net income (loss)	3,693	61	(709)	2,623	5,668
Earnings (loss) per common share - basic	1.01	(0.01)	(0.22)	0.71	1.49
Earnings (loss) per common share - diluted	0.99	(0.01)	(0.22)	0.69	1.46

(\$ in thousands, except per share data)

2002

	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	\$ 36,090	\$ 23,370	\$ 16,714	\$ 32,889	\$ 109,063
Net income (loss)	3,316	893	(889)	1,270	4,590
Earnings (loss) per common share - basic	0.91	0.23	(0.28)	0.34	1.20
Earnings (loss) per common share - diluted	0.90	0.22	(0.28)	0.34	1.18

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NATURAL GAS DELIVERIES

Natural gas deliveries in 2003 totaled 36 638 terajoules* compared with 39 463 terajoules in 2002. A comparison of 2003 and 2002 deliveries is provided in the following table:

Deliveries in terajoules	2003	2002	% Change
Sales:			
Residential	3 464	3 503	(1.1)
Commercial	2 845	2 897	(1.8)
Small Industrial	825	1 050	(21.4)
Large Industrial	620	595	4.2
Total Sales	7 754	8 045	(3.6)
Transportation Service:			
Commercial	64	70	(8.6)
Small Industrial	2 764	2 755	0.3
Large Industrial	26 056	28 593	(8.9)
Total Transportation Service	28 884	31 418	(8.1)
Total Deliveries	36 638	39 463	(7.2)

* The joule is a metric energy measurement unit. One gigajoule (GJ) is equivalent to 0.94782 British thermal units (BTU). One terajoule (TJ) equals one thousand GJ. One petajoule (PJ) equals one million GJ. In volumetric units, 1000 cubic meters is equivalent to 35.301 thousand cubic feet.

Transportation deliveries to large industrial customers decreased 8.9 percent from 2002 to 2003 due to a four-month labour dispute at West Fraser Mills Ltd.'s ("West Fraser") Kitimat linerboard and kraft paper mill (formerly referred to as Eurocan) and a five-week maintenance shutdown at the Kitimat methanol/ammonia facility of Methanex Corporation ("Methanex").

While 2003 deliveries to residential and commercial customers declined slightly from 2002 levels, this can be partially attributed to the weather being approximately 1% warmer in 2003 than in 2002.

CUSTOMER ADDITIONS

In 2003, 284 new services were connected to the Company's distribution systems, compared with 270 in 2002. This increase in service additions is the result of continued strong economic activity in the northeastern service area. Although 284 new services were connected, the Company experienced a net loss of 148 customers. This is a result of 432 customers leaving the distribution system, primarily in the Company's west central service area.

In mid-2001, the Company implemented a modified main extension and service connection policy. These changes require new customers to fully cover the cost of service line connections to the distribution system. Also, in situations where main extensions are required, initial customers must fund the full amount of any shortfall between the Company's allowable investment and total estimated construction costs. This has eliminated the Company's role in financing a portion of main extension costs until all anticipated customers are connected to a new main.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited remaining opportunity to extend gas mains into unserved rural areas in the Western service area.

NATURAL GAS SUPPLY

All of the Company's residential customers, most of its commercial customers and a number of its small industrial customers purchase gas from the Company at rates which include the gas commodity cost and the Company's cost of delivering gas to the customers' premises. The gas commodity cost paid by the Company to its gas suppliers is passed through without mark-up to customers.

The British Columbia Utilities Commission (the "Commission") reviews the gas commodity portion of the Company's rates on a quarterly basis to ensure close alignment with the prevailing market prices for natural gas. Any variances in gas commodity prices paid by the Company from those included in current retail rates are deferred for subsequent refund to or recovery from customers. To moderate the variability of the gas supply commodity prices paid, the Company uses financial instruments under a gas price management plan that is filed with the Commission on an annual basis.

A gas supply contracting plan is also prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The Company purchases gas from gas producers under long-term and short-term gas purchase contracts. The gas contracting plan is designed to ensure the Company has adequate gas supplies at reasonable prices to meet the requirements of its customers on the coldest day of the year, normally referred to as the peak day. Contracted gas that is surplus to customer requirements is sold into other markets at prevailing market prices. Most of the Company's contracted gas supply is produced in British Columbia.

The Company's large industrial customers, the majority of its small industrial customers, and a few large commercial customers arrange for delivery of their gas supply requirements to the Company. These customers contract for gas transportation service on the Company's pipeline systems. Some of these customers also purchase gas from the Company to supplement their gas supply as may be required from time to time and subject to gas supply availability from the Company.

For 2003, approximately 28 percent of gas purchases were hedged pursuant to the Company's gas price management plan. Note 14 to the Consolidated Financial Statements provides further information as of December 31, 2003 with regard to 2004 gas supply.

Virtually all of the Company's gas supply is comprised of the pooled gas stream available from the Duke Energy Gas Transmission ("Duke Energy") pipeline system. This includes all of the supply to the Company's transmission line serving its Western service area and approximately 73 percent of the supply for the Fort St. John and Dawson Creek service areas.

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In addition to the supply from the Duke Energy system, the Fort St. John system incorporates two interconnections with Canadian Natural Resources Limited's West Stoddart Pipeline, providing 37 percent of the system's requirements. In Dawson Creek approximately 12 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects the Company's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities.

A long-term contract with CanWest Gas Supply Inc. accounted for about 67 percent of 2003 purchases. Other supplies included purchases under seasonal and spot gas supply arrangements.

LARGE INDUSTRIAL CUSTOMERS

The Company has firm transportation service and interruptible sales/service agreements with three of its large industrial customers: Methanex, West Fraser and Alcan Smelters and Chemicals Ltd. ("Alcan").

The Company delivers gas to its other large industrial customer, British Columbia Hydro and Power Authority ("BC Hydro"), under an interruptible sales/service agreement for emergency electric power generation at BC Hydro's facility in Prince Rupert.

The large industrial customers produce commodities that are subject to world commodity price fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue operation during sustained periods of low commodity prices.

Deliveries to Methanex in 2003 accounted for approximately 65 percent of volumes delivered by the Company and approximately 9.3 percent of the Company's operating revenues. Transportation service to Methanex in 2003 was provided pursuant to an agreement that expires October 31, 2009. An annual demand charge based on a firm toll of 50 cents per gigajoule applies over the term of the agreement. In addition, under the contract, Methanex supplies a portion of the Company's internal gas requirements equal to four percent of deliveries to Methanex. The contract also includes a profit-sharing mechanism during periods of high methanol prices and relatively low natural gas prices. The profit-sharing mechanism did not result in any additional revenue to the Company in 2003.

The Company's 2003 rate application to the Commission assumed a prospective new transportation contract with New Skeena Forest Products Inc. ("Skeena") for service to its pulp mill in Prince Rupert. It was expected that the pulp mill would operate for six months during 2003, however the plant failed to open in 2003. As a result, the Company recorded deferred charges of \$1.1 million net of tax in its industrial customer deliveries deferral account relating to Skeena. These charges will be amortized in rates and collected from customers over a three-year period beginning in 2004 subject to Commission approval of the amortization period.

The transportation service and sales contracts with West Fraser and Alcan are in effect through October 31, 2004 and October 31, 2005, respectively. The agreement with Alcan will continue in effect past October 31, 2005 unless Alcan or the Company gives notice of termination. In February 2004, the Company signed a memorandum of agreement with

West Fraser for a new 10-year transportation contract with an effective date of January 1, 2004. The contract, which provides for a toll that is approximately 30 percent lower than the toll currently in effect, is subject to approval by the Commission. During 2003, deliveries to West Fraser and Alcan accounted for 7.8 percent of the Company's total gas deliveries and 6.7 percent of operating revenues.

In May 2003, the linerboard and kraft paper mill in Kitimat operated by West Fraser shut down due to a labour dispute. Operations did not recommence until September when West Fraser entered into a five-year collective agreement with its unions. The shutdown at the plant reduced the Company's net earnings in 2003 by \$0.1 million.

REGULATORY ACTIVITIES

Pacific Northern Gas is subject to regulation under the Utilities Commission Act of British Columbia. The Commission regulates the business of the Company, including the construction and operation of major facilities, the issuance of securities, the determination of rates for the sale and transportation of gas, and the terms and conditions of service.

In approving rates, the Commission must determine that the rates reflect a fair and reasonable charge for service of the nature and quality furnished to customers. The rates should be sufficient to enable the Company to earn a fair and reasonable compensation for its services and a fair and reasonable return upon the value of its property.

The Commission determines customer rates using a fixed rate approach on the basis of forecasts of both the cost of service and the volumes of gas delivered through the transmission and distribution systems. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is the sum of the depreciated cost of property, plant and equipment that is used or useful in serving the Company's customers, plus a reasonable allowance for working capital. The Commission determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital.

Revenue requirements applications for all service areas are submitted to the Commission, generally on an annual basis. The Commission may consider these applications through a public hearing process (either oral or written), or through negotiations with the customers under alternate dispute resolution processes supervised by Commission staff.

In November 2002, the Company filed applications with the Commission for approval of new rates to be effective January 1, 2003 for all service areas. The revenue requirement applications for 2003 were considered by the Commission through an alternative dispute resolution process for the Western transmission and distribution systems ("Western System") and a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions.

Agreement was reached on the Company's 2003 revenue requirements application on February 21, 2003 for the Western System. The 2003 allowed rate of return on common equity was 10.17 percent, based on a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a 75 basis point premium over the low risk benchmark utility rate of return.

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The Commission issued its decisions on the 2003 revenue requirements applications on March 27, 2003 for the Fort. St. John/Dawson Creek and Tumbler Ridge divisions. The 2003 allowed rate of return on common equity was 9.82 percent for the Fort St. John/Dawson Creek division and 10.07 percent for the Tumbler Ridge division, based on a deemed common equity component of rate base of 36 percent. The allowed rate of return on common equity includes a 40 basis point premium over the low risk benchmark utility rate of return (65 basis point premium for the Tumbler Ridge division).

In 2003, the Company received approval for a new deferral account for all regulatory divisions to record variances between projected and actual gas consumption by residential and small commercial customers (a Rate Stabilization Adjustment Mechanism, or "RSAM"). The objective of the RSAM deferral account is to manage the forecast risk associated with weather and other factors affecting gas consumption. If the actual gas use per customer account varies from the forecast average use per account approved by the Commission, the financial impact of the difference is deferred for future recovery or refund to the customer. In 2003, the Company recorded deferred charges of \$0.9 million net of tax in the RSAM, which will be recovered from customers over three years beginning in 2004.

WESTERN SYSTEM

For 2003, the Commission continued its direction to defer the difference between actual sales to Methanex, Skeena, West Fraser and B.C. Hydro and the forecast sales used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). Alcan was also added to the ICDDA for 2003 under the settlement terms of the 2003 revenue requirement application. The availability of the ICDDA increased 2003 net earnings by \$1.1 million. The Commission also accepted the Company's forecast of gas supply costs for 2003. Rate riders were approved in various amounts for 2003 to refund a credit balance accumulated in the gas purchase variance payable account. In 2003, the reduction in customer revenue from credit rate riders totalled \$2.1 million, and was applied, on an after tax basis, to reduce the gas purchase variance payable account.

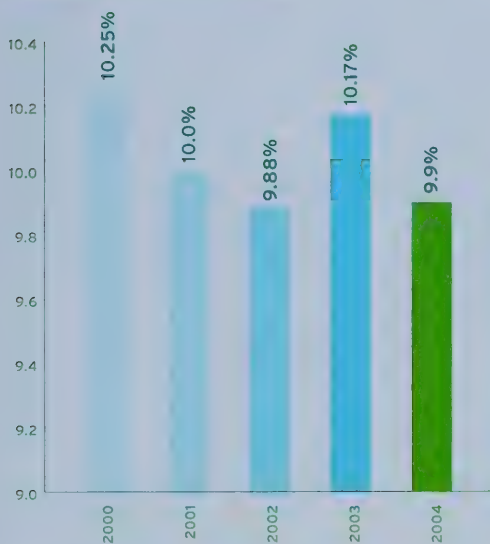
The 2004 revenue requirement application for the Western system was filed with the Commission at the end of November 2003. The application reflected an increase to the delivery charges offset by a reduction in the gas supply commodity charges. The 2004 forecast gas supply commodity charges are approximately 19 percent lower than what was embedded in rates effective December 31, 2003. The Commission accepted the Company's gas supply price forecast and decreased the gas supply commodity cost component of rates accordingly, effective January 1, 2004.

In the revenue requirements application, residential and commercial deliveries in 2004 in the Western system are forecast to increase by approximately five percent compared to 2003 actual volumes. The deliveries to small industrial customers are projected to be higher in 2004 by approximately six percent. The 2004 application assumed that the Skeena Prince Rupert pulp mill and sawmills in Terrace and Smithers would not operate in 2004.

In February 2004 the Company filed an update to its 2004 revenue requirements application reflecting, among other things, the memorandum of agreement signed with West Fraser for a new transportation service contract effective January 1, 2004. The agreement, which is subject to approval by the Commission, provides for a transportation toll that is approximately 30 percent lower than in effect under the current contract with West Fraser. The update to the application contained adjustments to other customers' rates required to ensure the Company remains revenue neutral. The 2004 revenue requirements application for the Western system and the new agreement with West Fraser will be the subject of a public hearing process in late March 2004.

In December 2003, the Commission confirmed that its formula for determining the allowable return on common equity in 2004 resulted in a 9.15 percent return for a low risk benchmark utility for the year. For the Company, a return on equity risk premium of 75 basis points applies to the Western system resulting in an allowable return on common equity of 9.90 percent for 2004. The Commission approved interim rates effective January 1, 2004 based on a 36 percent deemed common equity component of the capital structure.

PNG WEST ALLOWED RETURN ON COMMON EQUITY 2000 - 2004



FORT ST. JOHN / DAWSON CREEK DIVISION

The Commission accepted the Company's forecast of gas supply costs for 2003. Rate riders were approved for 2003 to recover debit balances recorded in the gas purchase variance recoverable account at December 31, 2002 over a period of three years. In 2003, customer revenue from rate riders totalled \$0.7 million, which was applied, on an after tax basis, to reduce the gas purchase variance recoverable account.

The Fort St. John/Dawson Creek 2004 revenue requirements application, filed in November 2003, sought Commission approval to increase the gas delivery charge component of its natural gas rates and to decrease the gas commodity charges. The Commission approved interim rates based on deemed common equity of 36 percent, and an allowable return on common equity of 9.65 percent for 2004. The interim rates, effective January 1, 2004, resulted in rate decreases of between 13 and 14 percent for residential and small commercial customers, respectively.

TUMBLER RIDGE DIVISION

The Tumbler Ridge 2004 revenue requirement application was filed with the Commission at the end of November 2003. The application sought Commission approval to decrease the gas delivery charge component of natural gas rates primarily due to lower projected gas requirements for internal company use. The gas commodity charge component of rates also decreased. The Commission approved interim rates, effective January 1, 2004, resulting in rate decreases of approximately nine percent for residential and small commercial customers.

The Commission is conducting a written hearing process in respect of the Fort St. John/Dawson Creek and Tumbler Ridge divisions. The Commission is expected to render a decision on the application in the second quarter of 2004.

ENVIRONMENTAL, HEALTH & SAFETY

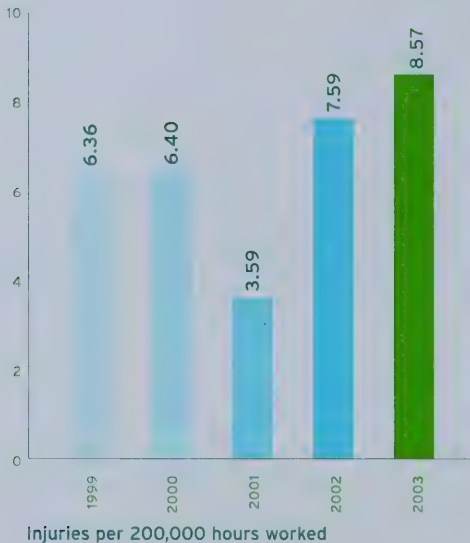
Transmission pipelines are constructed with pressure tested steel and covered with a protective coating to prevent corrosion. The Company utilizes a 24-hour per day Gas Control Centre with computer control of its pipeline system, commonly referred to as SCADA (Supervisory Control And Data Acquisition) to aid in the safe operation of its system. This system allows pipeline operations staff to monitor pipeline flow, pressure

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conditions and trends, to start and stop compressor units, and to open or close pressure control valves - all from a central control center. The SCADA system is capable of detecting and correcting various events that could impact system integrity. Unusual conditions trigger alarms to which field staff respond to verify problems and take corrective action if necessary. The Company also conducts regular aerial and land surveillance of the pipeline to check for corrosion, leaks, vegetation, and development encroachment.

Although the same number of recordable injuries occurred in 2003 as in 2002, a fewer number of person hours worked in 2003 compared to 2002 resulted in a higher injury frequency rate. The frequency of recordable injuries increased by 43 percent in 2003 compared to the average for the previous four years.

FREQUENCY RATE OF RECORDABLE INJURIES



ENGINEERING AND OPERATIONS

IN-LINE INSPECTION

The Company has processes in place to monitor the ongoing integrity of its transmission pressure pipeline to ensure protection of the public and the environment by demonstrating that all transmission pipelines are suitable for continued safe and reliable service. A key aspect of these processes focuses on the internal inspection of the pipeline using In Line Inspection ("ILI") tools and subsequent repair activities that arise from the information gathered.

The Company began implementing ILI programs on its transmission pipeline in 1989. The 2003 ILI activity involved running the inspection tool from Terrace to Kitimat in the ten-inch line, and from Vanderhoof to a point forty kilometers west in the twelve-inch loop pipeline. The results of these inspections were favourable. The Company intends to continue its ILI program in 2004 and into the foreseeable future at an annual level that continues to address the inherent risks in its ongoing operation.

COMPRESSOR CONTROL SYSTEMS

Installation of a programmable logic controller-based system at the Smithers compressor station was completed in 2003. The new system offers more reliable control and a greater level of operational flexibility, while allowing for remote control and troubleshooting of the compressor unit. A similar system is planned for installation at the Burns Lake compressor station in 2004, at which point all of the Company's compressor control systems will have been upgraded.

KHYEX RIVER SLIDE

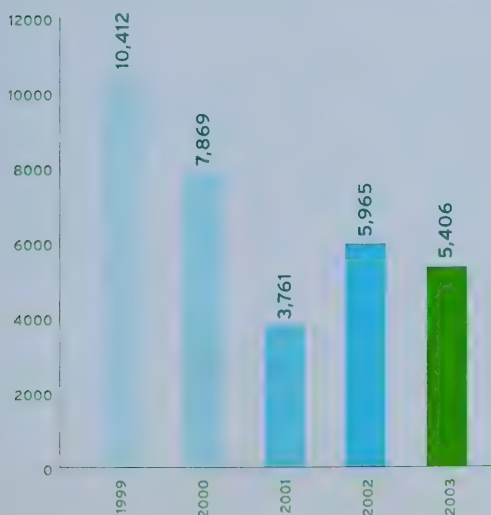
On November 28, 2003, a massive debris slide 55 kilometers east of Prince Rupert ruptured a section of the eight-inch high-pressure transmission pipeline. Service to four thousand customers in Prince Rupert and Port Edward was interrupted. Liquid natural gas and compressed natural gas were transported to the Prince

Rupert area by truck and were used to provide service to selected community facilities until a temporary repair could be completed. Installation of two two-inch and one four-inch temporary lines was completed within eight days of the line break, restoring service to all customers by December 6, 2003. The cost of the temporary repairs, totaling \$0.5 million net of income taxes, was deferred as line break expense and will be amortized into rates over ten years commencing in 2004. A permanent repair will be completed in 2004, and is included, net of insurance recoveries, in planned capital expenditures for 2004.

CAPITAL EXPENDITURES

Total capital expenditures in 2003 were 9 percent or \$0.6 million lower than those incurred in 2002 and 19 percent below the average level of expenditures for the last five years. However, capital expenditures in 2002 included \$1.7 million for the permanent repair of the Copper River line break, which occurred in mid 2002. Total capital expenditures prior to mid-year 2000 also included higher levels of expenditures on the upgrading and rehabilitation of the transmission pipeline system.

CAPITAL EXPENDITURES 1999 - 2003 (\$ in thousands)



CAPITAL EXPENDITURES

(\$ in thousands)	2003	2002
Transmission system	\$ 2,310	\$ 2,891
Distribution system	2,356	2,109
Processing plant	41	41
Other	699	924
Total	\$ 5,406	\$ 5,965

Planned capital spending in 2004 is primarily directed toward distribution mains and services, as well as transmission mainline permanent repairs and replacement, and is forecast to be approximately \$9.6 million. Included in this estimate is a planned rehabilitation expenditure of approximately \$1.8 million for replacement of a dual-line underwater transmission system river crossing of the Salmon River. Contractual commitments have yet to be made for major planned capital expenditures for 2004.

CAPITAL STRUCTURE AND FINANCING

CAPITAL STRUCTURE

Composition (percent)	At Dec. 31 2003	At Dec. 31 2002
Preferred shareholders' equity	2.9	3.0
Common shareholders' equity	42.2	40.9
Short-term debt	1.7	-
Long-term debt, including current portion	53.2	56.1
	100.0	100.0

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For rate determination purposes the Company is permitted to earn a return on its invested capital to the extent of its approved rate base. Rate base is composed of the depreciated book value of fixed assets, plus unamortized deferred charges, plus an allowance for working capital, less deferred income taxes. The Commission sets customer rates at a level that is intended to allow the Company to earn its allowed rate of return on common equity on 36 percent of rate base. The 36 percent is significantly below the 42.2 percent common equity on the Company's balance sheet.

Equity

On December 18, 2003, the Company's Memorandum and Articles were altered by changing the name and designation of all of the 6,000,000 issued and unissued Class A Non-Voting common shares to common shares. In addition, the name and designation of all of the 20,000 issued and unissued Class B Voting common shares were changed to common shares. As a result of this amendment, the holders of all of the Company's common shares are now entitled to vote at shareholders' meetings.

The book value of the common shares at December 31, 2003 was \$19.96 per share, compared to \$19.27 per share at December 31, 2002.

The Company's preferred shares are currently rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS").

Shares outstanding

During 2003, the Company issued 4,800 common shares under its stock option incentive plan, compared to 31,300 shares issued in 2002.

At December 31, 2003, there were 200,000 preferred shares and 3,583,880 common shares outstanding. This compares to 200,000 preferred shares, 3,559,080 Class A Non-Voting shares and 20,000 Class B Voting shares outstanding at December 31, 2002.

Dividends

Preferred dividends totaling \$1.6875 per share were paid in 2003, the same as in 2002.

Dividends on common shares totaling \$3.55 per share were paid in 2003. This included a special dividend of \$2.75 per common share paid in January 2003, and four quarterly dividends of \$0.20 per common share paid in March, June, September and December. The Company did not pay any dividends on common shares in 2001 or 2002.

A total of \$13.1 million preferred and common dividends were paid in 2003.

Short-term debt

The Company has a bank demand operating and hedge line of credit of \$25 million that bears interest at prime rate or bankers' acceptance rates and provides funds for general corporate and working capital requirements. The amount available under this facility is subject to borrowing base requirements. The line of credit is collateralized by the pledge of a \$25 million debenture and a charge on certain accounts receivable and inventories.

As a result of seasonality in operations, marginable receivables and other assets are significantly reduced in the second and third quarters, compared to the winter heating season, thus constraining availability of the demand line of credit. At December 31, 2003, the amount available under the facility was approximately \$7.1 million, \$2.9 million of which had been drawn under demand loans and \$2.0 of which was drawn in the form of letters of credit. The Company has provided covenants to its operating lender, all of which were complied with during 2003.

Long-term debt

The Company's secured debentures are currently rated BBB(low) by DBRS.

FUNDING PROGRAM

Funding requirements

The Company's capital expenditures, working capital needs, dividend payments and debt repayments are funded from a combination of sources. During 2003, the primary sources of funding were \$12.2 million of cash generated from operations, a drawdown of \$9.7 million of cash balances resulting from the issuance of \$15.0 million of long-term debt in December 2002, and a draw of \$2.9 million in demand loans under an operating line of credit.

Liquidity and capital resources

The Company purchases gas for resale to its core market customers, and passes through the commodity cost of gas to those customers without markup. The rates charged to core market customers are based in part on projected gas supply prices. The Company's liquidity requirements are affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases.

Financial ratios

At the end of 2003, interest coverage using earnings before interest, income taxes, depreciation, and amortization was 3.34 times compared to 3.75 times in the prior year, declining mainly as a result of interest on a \$15 million loan arranged by the Company near the end of 2002.

Funding costs

Interest expense

(\$ in thousands, except percent figures)

	2003	2002
Long-term interest expense	\$ 7,536	\$ 6,868
Short-term interest expense	573	662
Total	\$ 8,109	\$ 7,530
Effective blended cost of debt	8.7%	8.9%

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RISK FACTORS

BUSINESS AND OPERATING RISK

Industrial customer concentration

In 2003, 73 percent of energy deliveries were made to the Company's four largest industrial customers, compared to 74 percent in 2002. Two of these customers, totaling approximately 8 percent of annual deliveries, have firm gas transportation agreements expiring over the next two years. While the Company has signed a memorandum of agreement with one of these customers for a new long-term contract, the contract remains subject to regulatory approval. In addition, the Company's contract with Methanex expires in 2009. The Company's ability to negotiate new contracts and to renegotiate existing contracts could be limited by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability and price competitiveness of alternative energy sources.

The risk of non-performance by one or more of the large industrial customers may be analyzed and managed, but it cannot be entirely eliminated. In addition, the Company's service area is economically dependent upon industrial customers, many of which are tied to the forest sector. A prolonged decline in the forest and other related sectors could negatively impact deliveries to all customer classes.

Commodity price risk

The average commodity cost of natural gas remains relatively high and was more than 60 percent higher in 2003 compared to 2002. The prospect of fuel-switching and increased energy conservation by customers poses a risk as other energy sources become more cost competitive.

FINANCIAL RISK

Commodity price volatility

Fluctuations in the price of natural gas could increase the working capital financing requirements and related costs for accounts receivable, and high customer rates may give rise to higher bad debt costs.

Recovery of deferral accounts

The recovery of the Company's accumulated deferral accounts has an impact on the Company's liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval.

Cash generated from operations

The Company's investment activities are financed by cash generated from operations and drawings under its operating line, together with proceeds from the issue of long-term debt and share capital, which may not be available in the amounts expected or required.

Insurance risk

The Company maintains insurance against exposures to the physical loss of its pipeline, compressor and other above ground facilities, as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past experience, the deductibles have increased over time and, depending on the number and severity of future outages, the financial impact on the Company could be material.

OTHER

LITIGATION

Pacific Northern Gas (N.E.) Ltd. is involved in a legal dispute with a customer over the payment for gas delivered to the customer. The dispute relates to the customer's obligation to supply its own gas for transportation to their facilities, or failing that, to pay for gas delivered to those facilities. Approximately \$2 million relating to the dispute has been included in accounts receivable at December 31, 2003. The actual amount recovered could be different than this estimate.

EXPENSING STOCK OPTIONS

Effective January 1, 2003, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") standard for stock-based compensation on a prospective basis. Under the fair value method, compensation expense is measured at the grant date and recognized over the service period. The Company accounts for stock-based compensation in accordance with the fair value method and expensed stock-based compensation of \$56,000 in 2003 in respect of stock options granted after January 1, 2003.

VALUATION OF PROPERTY, PLANT AND EQUIPMENT

In 2003, the CICA approved a new accounting standard for the recognition, measurement and disclosure of the impairment of long-lived assets (Section 3063). The new standard applies to non-monetary long-lived assets, including property, plant and equipment, and intangible assets with finite useful lives. Under the new requirements, an impairment loss is recognized when the carrying amount of an asset to be held and used exceeds the sum of the undiscounted cash flows expected from its use and eventual disposition. An impairment loss is measured as the amount by which the asset's carrying amount exceeds its fair value. The Company will adopt the new accounting standard prospectively, beginning January 1, 2004, and it is expected that adoption of the new standard will have no material effect on the Company's financial position or earnings in 2004.

In 2003, the CICA approved a new accounting standard for the recognition, measurement and disclosure of liabilities for asset retirement obligations and the associated asset retirement costs (Section 3110). A company will be required to recognize the fair value of a liability for an asset retirement obligation in the period in which the obligation is incurred when a reasonable estimate of fair value can be made. The Company will adopt the new accounting standard prospectively beginning January 1, 2004, and it is expected that adoption of the new standard will have no material effect on the Company's financial position or earnings in 2004.

HEDGING RELATIONSHIPS

In 2003, the CICA approved new guidelines relating to the identification, designation, documentation and effectiveness of hedging relationships, for the purpose of applying hedge accounting (Accounting Guideline AcG-13). Specific documentation is required to qualify for hedge accounting prior to, at inception, and throughout the term of the hedging relationship, including risk management policies, specific designation of hedging relationships, the nature of risk being hedged, the hedge objective or strategy, effectiveness assessment methodologies, and accounting policies for hedge relationships, including income recognition. Retroactive and prospective effectiveness assessments will be required throughout the term of the hedge. The Company will adopt the new accounting guideline prospectively beginning January 1, 2004, and it is expected that adoption of the new guideline will have no material effect on the Company's financial position or earnings in 2004.

MD&A

OUTLOOK

2004 REVENUE REQUIREMENTS APPLICATIONS

The Company's 2004 revenue requirements applications were filed with the Commission in late 2003. The applications project that deliveries to residential and commercial customers will be 2.6 percent higher than experienced in 2003. Achieving the delivery forecast will be dependent upon a number of factors, including weather, the volatility and absolute level of gas prices, and the relative prices of competitive fuels. Natural gas prices for 2004 for gas purchases by the Company, based on forward gas prices as at February 24, 2004, are forecast to be approximately 2 percent (\$0.14 per GJ) higher than the actual corresponding prices in 2003.

APPLICATION FOR APPROVAL OF INCOME TRUST OWNERSHIP STRUCTURE

On January 30, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to an income trust called the "PNG Income Trust". The PNG Income Trust would be owned by unit holders that would be comprised of the current shareholders that would exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application will be reviewed through a public hearing process, with a decision by the Commission expected in the second or third quarter of 2004. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval, and acceptable market conditions. The Company can give no assurances that the required approvals will be obtained, or that the conversion to an income trust ownership structure will occur.

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RESPONSIBILITY FOR FINANCIAL STATEMENTS

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada and, where appropriate, include certain estimated amounts that are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of directors who are not employees of the Company or of its subsidiaries. The Audit Committee meets regularly with management, the internal auditors, and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities. The Audit Committee reports its findings to the Board of Directors.

Deloitte & Touche LLP, the independent auditors appointed by the shareholders, have full and free access to the Audit Committee. The auditors performed an independent audit of the consolidated financial statements for the years ended December 31, 2003 and December 31, 2002. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

January 30, 2004



Roy G. Dyce
President and Chief Executive Officer



Elizabeth A. Fletcher
Chief Financial Officer

AUDITORS' REPORT

TO THE SHAREHOLDERS OF PACIFIC NORTHERN GAS LTD.

We have audited the consolidated balance sheets of Pacific Northern Gas Ltd. as at December 31, 2003 and 2002 and the consolidated statements of income, retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied on a basis consistent with that of the preceding year, except for the changes in accounting policies described in note 1 to the consolidated financial statements.

Deloitte & Touche LLP

Chartered Accountants
Vancouver, Canada,
January 30, 2004.

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31 (\$ in thousands, except for per share amounts)	2003	2002
Operating revenues (notes 2 and 12)	\$ 133,727	\$ 109,063
Cost of sales (note 12)	84,417	56,820
	49,310	52,243
Operating and maintenance	12,387	13,885
Administrative and general	6,084	5,279
Amortization of deferred charges	503	1,700
Municipal and other taxes	3,982	4,259
Depreciation	7,873	7,953
	30,829	33,076
	18,481	19,167
Investment and other income	56	50
	18,537	19,217
Income deductions		
Interest on long term debt	7,536	6,868
Other	573	824
	8,109	7,692
Income before income taxes	10,428	11,525
Income taxes (note 4)		
- current	3,870	7,225
- deferred	890	(290)
	4,760	6,935
NET INCOME FOR THE YEAR	\$ 5,668	\$ 4,590
FOR COMMON SHARES		
Net income for the year	\$ 5,668	\$ 4,590
Provision for dividends on preferred shares	337	337
Net income applicable to common shares, basic and diluted	\$ 5,331	\$ 4,253
EARNINGS PER COMMON SHARE (note 6)		
Basic	\$ 1.49	\$ 1.20
Diluted	\$ 1.46	\$ 1.18

See accompanying notes

CONSOLIDATED BALANCE SHEETS

ASSETS (notes 7, 8)

as at December 31 (\$ in thousands)	2003	2002
CURRENT ASSETS		
Cash and short term investments	\$ 313	\$ 10,027
Accounts receivable (notes 2, 12 and 15)	25,100	21,236
Inventories of supplies and natural gas	2,215	1,365
Prepaid expenses	133	200
	27,761	38,828
 PLANT, PROPERTY AND EQUIPMENT (note 3)	 174,348	 177,314
 DEFERRED CHARGES		
Debt expense	915	982
Rate stabilization adjustment mechanism	864	-
Pipeline rehabilitation costs	1,093	575
Other	1,433	807
	4,305	2,364
	\$ 206,414	\$ 212,506

See accompanying notes

On behalf of the Board:



Roy G. Dyce
Director



Robert F. Chase
Director

CONSOLIDATED BALANCE SHEETS

LIABILITIES

as at December 31 (\$ in thousands)

	2003	2002
CURRENT LIABILITIES		
Bank indebtedness (note 7)	\$ 2,900	\$ -
Accounts payable and accrued liabilities (note 12)	15,054	23,961
Gas purchase variance payable	3,562	2,678
Income and other taxes payable	2,737	1,845
Long term debt due within one year (note 8)	4,382	4,379
	28,635	32,863
Long term debt (note 8)	85,827	90,224
Deferred income taxes (note 4)	15,430	15,453
	129,892	138,540

Commitments and contingency (notes 14, 15 and 16)

SHAREHOLDERS' EQUITY (note 19)

Preferred shares (note 9)	5,000	5,000
Common shares (notes 10 and 11)	8,960	8,948
Contributed surplus (notes 10 and 11)	2,379	2,299
Retained earnings	60,183	57,719
	71,522	68,966
	76,522	73,966
	\$ 206,414	\$ 212,506

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Years ended December 31 (\$ in thousands)	2003	2002
BALANCE, BEGINNING OF YEAR	\$ 57,719	\$ 63,318
Net income for the year	5,668	4,590
	63,387	67,908
Preferred share dividends	337	337
Common share dividends	2,867	9,852
	3,204	10,189
BALANCE, END OF YEAR	\$ 60,183	\$ 57,719

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOW

Years ended December 31 (\$ in thousands)	2003	2002
OPERATING ACTIVITIES		
Net income for the year	\$ 5,668	\$ 4,590
Add (deduct) items not involving cash:		
Deferred income taxes	890	(290)
Depreciation and amortization	8,452	9,727
Stock option expense (note 11)	56	-
Other	(913)	543
Operating cash flow	14,153	14,570
Non-cash working capital changes (note 17)	(1,926)	(1,776)
NET CASH PROVIDED BY OPERATING ACTIVITIES	12,227	12,794
INVESTING ACTIVITIES		
Additions to plant, property and equipment	(5,406)	(5,965)
Increase in deferred charges	(2,519)	(372)
NET CASH USED BY INVESTING ACTIVITIES	(7,925)	(6,337)
FINANCING ACTIVITIES		
Increase (decrease) in bank indebtedness	2,900	(8,675)
Issue of long-term debt	-	15,037
Repayment of long-term debt	(3,895)	(2,623)
Issue of common shares (note 10)	36	220
Dividends paid	(13,057)	(506)
NET CASH (USED BY) PROVIDED BY FINANCING ACTIVITIES	(14,016)	3,453
(DECREASE) INCREASE IN CASH AND SHORT-TERM INVESTMENTS DURING THE YEAR	(9,714)	9,910
Cash and short-term investments, beginning of year	10,027	117
CASH AND SHORT-TERM INVESTMENTS, END OF YEAR	\$ 313	\$ 10,027

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

I. SUMMARY OF ACCOUNTING POLICIES

REGULATION

Pacific Northern Gas Ltd. and its wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd., are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission"). The Commission exercises statutory authority over matters such as rates, including rate of return on equity and capital structure, construction and operation of facilities, accounting practices, tolls, charges and contractual agreements with customers. In order to comply with orders issued by the Commission, the timing of recognition of certain revenues and expenses may differ from that which would otherwise be required under Canadian generally accepted accounting principles. Significant differences include, but may not be limited to, the following accounting policies:

- Depreciation rates [notes 1 and 3]
- Deferral accounts [note 1]
- Income taxes [notes 1 and 4]
- Employee future benefit plans for post-retirement non-pension benefits [notes 1 and 5]
- Hedges, derivatives and other financial instruments [notes 1 and 14]

USE OF ESTIMATES

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

CONSOLIDATION

The consolidated financial statements include the accounts of Pacific Northern Gas Ltd. and its wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. ("the Company").

STOCK-BASED COMPENSATION

Effective January 1, 2003, the Company adopted, on a prospective basis, the new recommendations of the CICA Handbook section 3870, "Stock-Based Compensation and Other Stock-Based Payments", which require the use of a fair-value based method to record stock-based compensation. This section establishes standards for the recognition, measurement and disclosure of stock-based compensation and other stock-based payments made in exchange for goods and services.

In 2002 the Company used the intrinsic valued based method to account for stock-based compensation transactions with employees. The pro forma effect on net income and earnings per share had the Company used a fair value based method to account for such compensation in 2002 is disclosed in Note 11.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The effect of adopting this new accounting policy in 2003 was to decrease net income for the year ended December 31, 2003 and to increase the balance of contributed surplus at December 31, 2003, both in the amount of \$56,000.

The Company has one stock-based compensation plan, which is described in Note 11.

REVENUE RECOGNITION

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues that are recorded as service is provided, as well as sales of gas surplus to the needs of the Company's sales customers ("off system sales") that are recognized when the gas is delivered.

CASH AND SHORT-TERM INVESTMENTS

Cash and short-term investments are held for the purpose of meeting short-term cash commitments and includes bank balances and term deposits with maturities of less than 90 days.

INVENTORIES OF SUPPLIES AND NATURAL GAS

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

PLANT, PROPERTY AND EQUIPMENT

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. As directed by the Commission, the cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are as follows:

(in percentages)	2003	2002
Transmission plant	2.9	2.9
Distribution plant	2.6	2.6
General plant	5.3	5.6
Processing plant	4.9	4.8
Composite rate	3.0	3.0

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF ACCOUNTING POLICIES (CONT'D)

DEFERRAL ACCOUNTS

A Debt expense

Debt expense comprises issue costs of long-term debt, which are amortized on a straight-line basis over the term of the related issue.

B Gas purchase variance payable

As directed by the Commission, gas purchase variance costs, which arise due to unanticipated commodity cost and demand fluctuations, are being charged or credited to cost of sales on a straight-line basis over periods ranging from one to three years. The amount of such credits to cost of sales in 2003 was \$1,363,000 before income tax (2002 - \$1,254,000).

C Pipeline rehabilitation costs

In 2003, the Company deferred costs of \$651,000, net of income taxes, relating to temporary repairs of pipeline breaks. The ultimate realization of these deferred charges is subject to a future decision of the Commission.

As directed by the Commission, pipeline rehabilitation costs are being amortized on a straight-line basis over ten years. The total amount of amortization of pipeline rehabilitation costs in 2003 was \$128,000 (2002 - \$204,000).

D Large Industrial Customer Margin Deferral

As directed by the Commission, a deferral account was set up to recover the lost margin from certain large industrial customers whose demand fell short of expectations. Total costs of \$1,116,000 net of income tax, (2002 - \$230,000) were deferred and included in other deferred charges. These amounts will be amortized commencing in 2004. The Company has applied to the Commission for a three-year amortization period of the 2003 deferral.

E Rate Stabilization Adjustment Mechanism

As directed by the Commission, the Company established a rate stabilization adjustment mechanism in 2003 to record the variance between actual and budgeted natural gas deliveries to residential and small commercial customers. The financial impact of the difference in deliveries is deferred for future recovery from or refund to the customers over a three-year period, commencing in 2004. During 2003, \$864,000, net of income taxes, was credited to income in respect of this deferral.

F Other

As directed by the Commission, various other costs have been deferred to be recovered from future revenues over periods ranging from 1 to 10 years. During 2003, \$87,000 was charged (2002 - \$1,075,000 credited) to income, net of income taxes, in respect of these deferred costs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

INCOME TAXES

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

EMPLOYEE FUTURE BENEFIT PLANS

The Company uses the pay-as-you-go method of accounting for non-pension post-retirement benefits as directed by the Commission. The Company accrues its pension obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value and obligations are discounted using a current market interest rate.

The excess of the net unamortized cumulative actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of the plan asset at the beginning of the year is amortized over the average remaining service period of the active employees. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 14 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

FINANCIAL INSTRUMENTS

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counterparties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

COMPARATIVE FIGURES

Certain of the prior year figures have been reclassified to conform to the current year's presentation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. MAJOR CUSTOMERS

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

(in percentages)	2003		2002	
	ENERGY	OPERATING REVENUES	ENERGY	OPERATING REVENUES
Methanex Corporation	65	9	65	19
West Fraser Mills Ltd., Alcan Inc. and British Columbia Hydro and Power Authority	8	8	9	6

At December 31, 2003, 8 percent (2002 - 10 percent) of accounts receivable was attributable to these four customers.

3. PLANT, PROPERTY AND EQUIPMENT

(\$ in thousands)	2003	2002
Transmission plant	\$ 177,779	\$ 175,578
Distribution plant	82,713	80,929
General plant	20,095	19,491
Processing plant	553	512
Construction in progress	649	603
Total plant, property and equipment	281,789	277,113

ACCUMULATED DEPRECIATION

Transmission plant	69,389	64,399
Distribution plant	27,791	25,821
General plant	9,949	9,224
Processing plant	312	355
Total accumulated depreciation	107,441	99,799
	\$ 174,348	\$ 177,314

During the year, the Company received contributions in aid of construction of \$176,000 (2002 - \$85,000), which have been recorded as a reduction of distribution plant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. INCOME TAXES

Significant components of the Company's deferred tax liabilities are as follows:

(\$ in thousands)	2003	2002
DEFERRED INCOME TAX LIABILITIES		
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	\$ 14,462	\$ 14,462
Other	968	991
Deferred income tax liabilities	\$ 15,430	\$ 15,453

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

(In percentages)	2003	2002
Combined Canadian federal and provincial statutory income tax rates, including surtaxes	37.6	39.6
Increase (decrease) in income taxes resulting from:		
Large corporations tax	4.5	2.9
Depreciation in excess of capital cost allowance	6.6	5.9
Amortization of intangibles	1.8	5.9
Deferred charge expenditures deducted for tax purposes	0.2	1.1
Other items	(5.1)	4.7
Effective rate of income taxes	45.6	60.1

From July 1, 1978 until its suspension on November 1, 1986, the deferral method of accounting for income taxes was followed by the Company. Had the deferral method been followed continuously since the inception of the Company, the deferred income tax liabilities and deferred income tax expense (recovery) would be:

(\$ in thousands)	2003	2002
Unrecorded deferred tax liabilities - long term, beginning of year	\$ 15,084	\$ 15,250
Unrecorded deferred income tax (recovery) expense	(279)	(166)
Unrecorded deferred tax liabilities - long term, end of year	14,805	15,084
Deferred tax liabilities, as reported	15,430	15,453
Total deferred tax liabilities	\$ 30,235	\$ 30,537

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. EMPLOYEE FUTURE BENEFIT PLANS

The Company and its subsidiary have defined benefit pension plans, defined contribution pension plans as well as defined benefit plans that provide post-retirement health and life insurance benefits for most employees.

Information about the defined benefit pension plans is as follows:

(\$ in thousands)	2003	2002
		AS RESTATED
ACCRUED BENEFIT OBLIGATIONS		
Balance, beginning of year	\$ 15,323	\$ 13,154
Current service cost	419	427
Employees' contributions	4	14
Interest cost	987	947
Benefits paid	(680)	(1,026)
Actuarial losses (gains)	1,171	1,807
Balance, end of year	\$ 17,224	\$ 15,323
PLAN ASSETS		
Fair value, beginning of year	\$ 11,601	\$ 11,566
Actual return on plan assets	1,426	792
Employer contributions	369	255
Employees' contributions	4	14
Benefits paid	(680)	(1,026)
Fair value, end of year	\$ 12,720	\$ 11,601
Funded status - plan deficit	\$ (4,504)	\$ (3,722)
Unamortized net actuarial losses	4,456	3,742
Unamortized past service costs	1	3
Unamortized transitional asset	(24)	(22)
Employer contribution - fourth quarter	109	112
Accrued benefit assets	\$ 38	\$ 113

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

During 2003, the Company determined that certain prior period note disclosures of pension plan assets, funded status and unamortized net actuarial losses should be revised due to measurement errors in 2001 and 2002. Details of the amounts as originally reported and as restated are as follows:

DECEMBER 31, 2002 (\$ in thousands)	AS ORIGINALLY REPORTED	AS RESTATED
PLAN ASSETS		
Fair value, beginning of year	10,433	11,566
Actual return on plan assets	3,214	792
Fair value, end of year	12,890	11,601
Funded status - plan deficit	(2,433)	(3,722)
Unamortized net actuarial losses	2,356	3,742
Accrued benefit assets	16	113

The revisions to the December 31, 2002 reported value of plan assets, actual return and unamortized net actuarial losses did not result in a material change to the reported financial position or results of operations of the Company and therefore no prior period adjustment was recorded.

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued pension benefit obligations:

(in percentages)	2003	2002
Discount rate	6.00	6.50
Expected long-term rate of return on plan assets	7.50	7.75
Rate of compensation increase	3.25	3.25

The Company's pension plan expense is as follows:

(\$ in thousands)	2003	2002
Current service cost	\$ 419	\$ 427
Interest cost	987	947
Expected return on plan assets	(1,116)	(987)
Amortization of past service costs	2	-
Amortization of net actuarial costs	40	-
Amortization of transitional asset	2	(9)
Net defined benefit pension plan expense	334	378
Defined contribution pension plan expense	49	75
Total pension expense	383	453

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. EMPLOYEE FUTURE BENEFIT PLANS (CONT'D)

The non-pension post-retirement benefit plan is unfunded and had an unrecognized accrued benefit obligation of \$4,739,000 at December 31, 2003 (December 31, 2002 - \$3,099,000).

Payments made during the year for non-pension post-retirement benefits, which are accounted for on a pay-as-you-go basis, were \$101,000 (2002 - \$71,000). Had the accrual methodology been followed, the non-pension post-retirement benefits expense would have increased by \$552,000 (2002 - \$277,000).

6. EARNINGS PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per common share are calculated using an adjusted average number of common shares outstanding during the year that reflect the potential exercise of dilutive share purchase options.

There are 71,500 (2002 - 102,700) stock options outstanding that could potentially dilute basic earnings per share in the future but were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

(\$ in thousands)	2003	2002
Net income applicable to common shares		
- basic and diluted	\$ 5,331	\$ 4,253
Weighted average number of common shares outstanding		
- basic	3,583,121	3,553,445
Effect of dilutive stock options	58,119	37,930
Weighted average number of common shares outstanding		
- diluted	3,641,240	3,591,375
Earnings per common share		
- basic	\$ 1.49	\$ 1.20
- diluted	\$ 1.46	\$ 1.18

7. BANK INDEBTEDNESS

(\$ in thousands)	2003	2002
Bank demand operating line of credit	\$ 2,900	\$ -

The Company has a bank demand operating and hedge line of credit of \$25 million (2002 - \$20 million) which bears interest at prime rate or bankers' acceptance rates (December 31, 2003 - 4.5%; December 31, 2002 - 5.8%) and provides funds for general corporate and working capital requirements. The amount available under this facility is subject to borrowing base requirements. The line of credit is collateralized by the pledge of a \$25 million debenture and

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

a charge on certain accounts receivable and inventories. At December 31, 2003, the amount available under the facility was approximately \$7.1 million, \$4.9 million of which had been drawn, consisting of \$2.9 million on the operating line of credit and an outstanding letter of credit in the amount of \$2.0 million.

8. LONG TERM DEBT

(\$ in thousands)	2003	2002
SECURED DEBENTURES (a)		
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate (December 31, 2003 - 5.757%), payable in monthly installments of \$110,000, with a final installment of \$120,000 at maturity.	\$ 9,360	\$ 10,680
RoyNat Debenture due December 15, 2012, bearing interest at a floating rate (December 31, 2003 - 6.257%), payable in monthly installments of \$105,000, with a final installment of \$2,505,000 at maturity.	13,740	15,000
2011 Series, 10.75% due December 13, 2011, payable in annual installments of \$700,050, and \$800,000 in each of years 2009 and 2010 with a final installment of \$5,000,000 at maturity.	10,100	10,800
2018 Series, 8.75% due November 15, 2018, payable in annual installments of \$600,000, commencing November 15, 1999 and \$1,000,000 in each of the years 2014 to 2017, with a final installment of \$7,000,000 at maturity.	17,000	17,600
2025 Series, 9.30% due July 18, 2025, payable in annual installments of \$500,000, commencing July 18, 2004 with a final installment of \$9,500,000 at maturity.	20,000	20,000
2027 Series, 6.90% due December 2, 2027, payable in annual installments of \$500,000, commencing December 2, 2006 with a final installment of \$9,500,000 at maturity.	20,000	20,000
CONSTRUCTION ADVANCES AND OTHER (b)	9	523
	90,209	94,603
Long term debt due within one year (c)	4,382	4,379
	\$ 85,827	\$ 90,224

- a** Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's plant, property and equipment and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.
- b** Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.
- c** Payments required to meet sinking fund and retirement provisions during the next five years are as follows:

(\$ in thousands)	Year	\$
	2004	4,382
	2005	4,382
	2006	4,882
	2007	4,882
	2008	4,880

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

9. PREFERRED SHARES

(\$ in thousands)		2003	2002
AUTHORIZED			
1,400,000	cumulative redeemable junior preferred shares with a par value of \$10		
200,000	6.75% cumulative redeemable preferred shares with a par value of \$25 each		
ISSUED			
200,000	6.75% preferred shares	\$ 5,000	\$ 5,000

The 6.75% preferred shares are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption.

10. COMMON SHARES

(\$ in thousands)		2003	2002
AUTHORIZED			
Voting common shares with a par value of \$2.50 each		6,020,000	-
Class A non-voting common shares with a par value of \$2.50 each		-	6,000,000
Class B voting common shares with a par value of \$2.50 each		-	20,000
ISSUED			
3,583,880	Common shares	\$ 8,960	\$ -
3,559,080	Class A common shares	-	8,898
20,000	Class B common shares	-	50
		\$ 8,960	\$ 8,948

During 2003, the Company issued 4,800 common shares (2002 - 31,300) for cash consideration of \$36,000 (2002 - \$ 220,000) upon the exercise of employee options. Of this amount, \$24,000 (2002 - \$141,000) has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

On December 18, 2003, the Company's Articles of Association and Memorandum were altered by changing the name and designation of all of the 6,000,000 issued and unissued Class A Non-Voting common shares to common shares. In addition, the name and designation of all of the 20,000 issued and unissued Class B Voting common shares were changed to common shares.

11. STOCK OPTION PLAN

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Share options generally vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As of December 31, 2003, 350,280 (2002 - 355,080) shares are reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

In 2003, 34,600 options were issued at an exercise price of \$14.15.

Commencing in 2003, the Company accounts for its grants under this plan in accordance with the fair value based method of accounting for stock-based compensation (see note 1). The compensation cost that has been charged against income (and credited to contributed surplus) in 2003 is \$56,000.

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions:

	2003
Dividend yield (percent)	4
Expected volatility (annualized) (percent)	44
Risk free interest rate (percent)	3
Expected years of option life (average)	7.5

In 2002, the Company used the intrinsic value based method to account for stock-based compensation transactions with employees. If the Company had used the fair-value based method to account for stock-based compensation, pro forma net income and earnings per common share would have been as follows:

(\$ in thousands except per share amounts)

		2002
Net income	As reported	\$ 4,590
	Pro forma	\$ 4,488
Net income applicable to common shares	As reported	\$ 4,253
	Pro forma	\$ 4,151
Basic earnings per common share	As reported	\$ 1.20
	Pro forma	\$ 1.17
Diluted earnings per common share	As reported	\$ 1.18
	Pro forma	\$ 1.15

The Company did not include those options outstanding at January 1, 2002 in its assessment of the 2002 pro-forma impact disclosed above.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. STOCK OPTION PLAN (CONT'D)

A summary of the status of the Company's stock option plan as of December 31, 2003 and 2002, and changes during the years ending on those dates is presented below:

	2003		2002	
	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	247,000	\$ 14.45	223,020	\$ 13.98
Granted	34,600	14.15	68,500	13.50
Exercised	(4,800)	7.52	(31,300)	7.00
Forfeited	-	-	(8,620)	14.60
Expired	(4,600)	14.13	(4,600)	14.13
Outstanding at end of year	272,200	\$ 14.52	247,000	\$ 14.45
Options exercisable at end of year	197,260	\$ 15.38	112,610	\$ 18.39
Weighted average remaining contractual life	6.6 years		7.2 years	

	Options Outstanding - 2003		Options Exercisable - 2003	
EXPIRY DATE	NUMBER OF SHARES	EXERCISE PRICE (\$)	NUMBER OF SHARES	EXERCISE PRICE (\$)
November 7, 2005	19,400	20.00	19,400	20.00
March 14, 2006	13,200	18.75	13,200	18.75
March 14, 2007	12,700	20.75	12,700	20.75
March 24, 2008	11,500	30.50	11,500	30.50
March 11, 2009	14,700	24.50	14,700	24.50
March 16, 2010	26,600	15.50	21,280	15.50
March 21, 2011	42,400	7.85	20,560	7.85
April 27, 2011	29,200	6.50	29,200	6.50
March 15, 2012	32,900	13.50	12,800	13.50
July 4, 2012	35,000	13.50	35,000	13.50
March 13, 2013	34,600	14.15	6,920	14.15
	272,200		197,260	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. RELATED PARTY TRANSACTIONS

The Company's transactions with related parties are as follows:

(\$ in thousands)	2003	2002
WESTCOAST ENERGY INC., PARENT COMPANY UNTIL DECEMBER 18, 2003		
Transportation services received	876	834
Materials purchases and services received	463	588
ENLOGIX CIS L.P., A COMPANY RELATED THROUGH COMMON CONTROL UNTIL SEPTEMBER 5, 2002		
Services received	-	510
WESTCOAST ENERGY RISK INC., A COMPANY RELATED THROUGH COMMON CONTROL UNTIL DECEMBER 18, 2003		
Services received	2,253	528
DUKE ENERGY MARKETING LP, AN ENTITY RELATED THROUGH COMMON CONTROL FROM MARCH 14, 2002 TO DECEMBER 18, 2003		
Natural gas purchases	19,385	2,034
ENGAGE ENERGY CANADA, L.P., AN ENTITY RELATED THROUGH COMMON CONTROL UNTIL DECEMBER 18, 2003		
Natural gas purchases and services received	197	5,323
Natural gas sales	23,121	15,110

Accounts payable and accrued liabilities as at December 31, 2003 include \$151,000 (2002 - \$5,014,000) and accounts receivable at December 31, 2003 include \$647,000 (2002 - \$4,364,000) relating to the above related party transactions.

These transactions are in the normal course of operations and are recorded at amounts established and agreed between the related parties, which approximate fair market value.

On March 14, 2002, all of the issued and outstanding common shares of Westcoast Energy Inc., the holder of all of the Company's voting shares, were acquired by an indirect wholly owned subsidiary of Duke Energy Corp.

On December 18, 2003, all of the common shares of the Company held by Westcoast Energy Inc. were acquired by Tricor Acquisition (STP) Inc., a subsidiary of Tricor Pacific Capital, Inc.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair values of debt instruments included in the consolidated balance sheets are as follows:

(\$ in thousands)	Carrying value		Fair value	
	2003	2002	2003	2002
Long term debt	90,209	94,603	92,501	89,402

The fair value of the Company's long-term debt is estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, gas purchase variance recoverable, bank indebtedness, and accounts payable and accrued liabilities approximate their carrying values.

14. NATURAL GAS AND INTEREST RATE CONTRACTS

The Company's tolls are set using a forecasted price for gas. However, some of the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices.

At December 31, 2003, the Company had outstanding fixed price contracts covering approximately 3.4 million gigajoules of natural gas to be delivered in the months from January to October 2004 (representing approximately 24 percent of forecast 2004 system gas supply) at prices ranging from \$4.92 to \$6.66 per gigajoule. In addition to the above mentioned fixed price contracts, at December 31, 2003 the Company has also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 1.0 million gigajoules of natural gas to be delivered in the months of January, February and March of 2004, (representing approximately 7 percent of forecast 2004 system gas supply).

At December 31, 2002, the Company had outstanding call options with a related party covering approximately 2.25 million gigajoules of natural gas to be delivered in the months of January and February 2003 (representing approximately 19 percent of forecast 2003 system gas supply).

The difference between the price of gas used for toll purposes and the actual cost of gas purchased, including call option premiums, is deferred and refunded to or recovered from customers as directed by the Commission.

The fair values receivable (payable) at December 31 under the contracts and options are as follows:

(\$ in thousands)	2003	2002
Fixed price contracts	\$ 1,041	\$ N/A
Collar contracts	(160)	N/A
Call options	N/A	-
	\$ 881	\$ -

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair values reflect the estimated amounts that the Company would receive or pay at December 31 to terminate the fixed price and collar contracts, based on the estimated future net cash flows under the terms of each contract, or the estimated amount that the Company would receive or pay at December 31 on settlement of the call options.

The Company's purchase commitments at December 31, 2003 under various gas supply contracts expiring through 2005 were as follows:

(\$ in thousands)

2004	\$ 63,537
2005	\$ 4,362
Thereafter	\$ -

Tolls for customers of Pacific Northern Gas (N.E.) Ltd. are predicated, among other things, on \$8,000,000 of long-term fixed rate debt financing provided by Pacific Northern Gas Ltd. Accordingly, the Company is party to an interest rate swap contract that converts the interest rate characteristics of \$8,000,000 of short-term borrowings from floating to a fixed rate of 7.7% until June 10, 2004. The swap contract has a fair value of \$200,000 payable at December 31, 2003 (\$549,000 payable at December 31, 2002). The fair value represents the amount the Company would have to pay to terminate the swap contract at December 31, based on the quoted market prices for similar instruments.

These estimated fair market values have no impact on earnings (see also note 13) due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

15. CONTINGENCY AND MEASUREMENT UNCERTAINTY

Pacific Northern Gas (N.E.) Ltd. is involved in a dispute with a customer over the payment for gas transported. The dispute relates to the customer's obligation to supply its own gas for transportation to its facilities, or failing that, to pay for gas delivered to those facilities.

On May 27, 2003 the Company commenced an action in the Supreme Court of British Columbia against the customer (the "Defendant"), claiming damages for breach of contract and for restitution for unjust enrichment in the amount of approximately \$2,020,000. The Company claimed that the Defendant had nominated no gas into the pipeline during a specified time period and, accordingly, the Defendant should have been charged a higher rate for gas delivered to the Defendant.

On June 25, 2003, the Defendant filed a statement of defence in which it claimed that it was not the original party to the gas supply agreement at the time of the alleged under billing and therefore not obligated to pay any back charges or, in the alternative, the provisions of the Company's gas tariffs restrict the period in which billing errors can be back charged to a customer.

On July 7, 2003, the Company filed a reply to the statement of defence in which it continued to assert its claim. The Company and the Defendant are still in the process of discovery with respect to the claims and no trial date has yet been set.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. CONTINGENCY AND MEASUREMENT UNCERTAINTY (CONT'D)

The Company believes it has a substantial case for recovery of the amounts billed and has recorded the related accounts receivable at management's best estimate of the amount ultimately recoverable. Approximately \$ 2 million relating to the dispute has been included in accounts receivable at December 31, 2003 and 2002.

16. COMMITMENTS AND GUARANTEES

Under the terms of its gas transportation and supply agreements with certain customers, the Company has provided an indemnity for all damages, claims or actions arising from any act or accident in connection with the installation, presence, maintenance and operations of the Company's property and equipment, or in connection with the presence of gas deemed to be in the possession and control of the Company, and carries insurance to cover losses in the event of any claims under these provisions. The Company has also provided an environmental indemnity to certain secured debenture holders for any losses arising from non-compliance by the Company with applicable environmental laws.

17. SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash working capital changes:

(\$ in thousands)	2003	2002
Accounts receivable	\$ (3,864)	\$ 393
Inventories of supplies and natural gas	(850)	155
Prepaid expenses	67	580
Accounts payable and accrued liabilities	945	3,241
Gas purchase variance payable	884	2,678
Income and other taxes payable	892	(8,823)
Attributable to operating activities	\$ (1,926)	\$ (1,776)

Included in accounts payable and accrued liabilities at December 31, 2002 are dividends payable of \$9,852,000.

Interest and tax payments:

(\$ in thousands)	2003	2002
Income taxes paid	\$ 3,690	\$ 15,136
Interest paid	\$ 7,877	\$ 7,289

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

18. SEGMENTED INFORMATION

The Company operates in one industry segment, the natural gas transmission and distribution segment, within Canada. The consolidated financial statements have therefore not been segmented.

19. SUBSEQUENT EVENT

On January 30, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of Pacific Northern from the current common shareholders to an income trust called the "PNG Income Trust". The PNG Income Trust would be owned by unit holders that would be comprised of the shareholders that exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application will be reviewed through a public hearing process, with a decision by the Commission expected in the second or third quarters of 2004. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval, and acceptable market conditions.

10 YEAR REVIEW

Years ended December 31 (\$ in thousands, except for per share amounts)	2003	2002	2001
DELIVERIES (TJ)			
Residential	3 464	3 503	3 470
Commercial	2 909	2 967	2 936
Small Industrial	3 589	3 805	3 592
Large Industrial	26 676	29 188	21 783
	36 638	39 463	31 781
CUSTOMERS AT YEAR END	39,106	39,254	39,230
Average rates per GJ			
Residential	\$ 11.21	8.62	\$ 11.31
Commercial	9.71	7.49	10.16
REVENUE			
Residential	\$ 38,815	30,204	\$ 39,239
Commercial	28,378	22,395	29,827
Small Industrial	9,545	9,479	10,539
Large Industrial	23,058	27,551	33,371
Off-System	33,403	18,763	24,736
Other	528	671	883
	133,727	109,063	138,595
EXPENSES			
Cost of Sales	84,417	56,820	83,344
Operating	22,453	23,423	24,189
Interest	8,053	7,642	8,797
Depreciation & amortization	8,376	9,653	10,581
Income taxes	4,760	6,935	5,969
	128,059	104,473	132,880
NET INCOME	\$ 5,668	4,590	\$ 5,715
PER COMMON SHARE			
Earnings	\$ 1.49	1.20	\$ 1.52
Dividends paid	3.55	-	-
CAPITALIZATION			
Long-term debt	\$ 85,827	90,224	\$ 79,539
Deferred income taxes	15,430	15,453	15,200
Preferred shares	5,000	5,000	5,000
Common equity	71,522	68,966	74,345
	\$ 177,779	179,643	\$174,084
UTILITY PLANT			
In service (net)	\$173,699	176,711	\$ 178,741
Construction in progress	649	603	560
	\$174,348	177,314	\$ 179,301

2000	1999	1998	1997	1996	1995	1994
4 216	4 202	3 688	3 796	3 056	2 644	2 580
3 543	3 108	2 897	3 162	2 559	2 217	2 183
3 875	3 694	3 704	2 972	2 120	1 905	1 924
23 137	31 573	28 498	32 365	30 981	27 890	31 339
34 771	42 577	38 787	42 295	38 716	34 656	38 026
39,665	39,238	38,808	37,669	27,978	26,638	25,714
\$ 8.20	\$ 6.16	\$ 5.80	\$ 5.68	\$ 4.90	\$ 5.30	\$ 5.31
5.96	4.84	4.41	4.41	3.58	4.58	4.65
\$ 34,557	\$ 25,881	\$ 21,380	\$ 21,552	\$ 14,971	\$ 14,026	\$ 13,708
21,115	15,036	12,763	13,952	9,157	10,161	10,148
9,349	6,356	4,912	4,848	3,354	4,013	3,903
36,108	29,967	31,883	35,166	33,842	30,237	34,125
14,108	-	754	1,804	1,068	2,119	-
496	498	452	539	431	442	442
115,733	77,738	72,144	77,861	62,823	60,998	62,326
61,750	24,778	20,887	27,295	14,975	19,943	22,281
23,297	22,876	20,615	19,877	16,611	16,518	16,527
9,293	9,050	9,307	8,903	8,822	8,915	7,918
8,866	8,094	8,322	7,067	6,792	5,646	4,969
5,689	5,815	6,559	6,793	8,238	3,785	4,030
108,895	70,613	65,690	69,935	55,438	54,807	55,725
\$ 6,838	\$ 7,125	\$ 6,454	\$ 7,926	\$ 7,385	\$ 6,191	\$ 6,601
\$ 1.83	\$ 1.92	\$ 1.73	\$ 2.16	\$ 2.01	\$ 1.67	\$ 1.80
0.56	1.12	1.10	1.00	0.96	0.94	0.88
\$ 82,158	\$ 85,593	\$ 88,894	\$ 92,135	\$ 74,862	\$ 80,056	\$ 63,990
15,653	12,789	11,126	7,119	1,863	15,514	15,731
5,000	6,715	10,261	13,609	18,910	5,000	5,000
68,968	64,311	61,459	59,142	54,785	51,038	48,432
\$ 171,779	\$169,408	\$ 171,740	\$172,005	\$150,420	\$151,608	\$ 133,153
\$ 182,016	\$182,766	\$ 178,614	\$ 176,103	\$156,995	\$154,421	\$145,047
1,335	151	1,610	1,459	1,244	1,929	2,590
\$ 183,351	\$ 182,917	\$180,224	\$ 177,562	\$158,239	\$156,350	\$ 147,637

CORPORATE INFORMATION

DIRECTORS

ROBERT F. CHASE^{1,2,4}

President and Chief Executive Officer
Lexacal Investment Corp.
West Vancouver, British Columbia

ROY G. DYCE

President and Chief Executive Officer
Pacific Northern Gas Ltd.
Coquitlam, British Columbia

J. TREVOR JOHNSTONE^{1,5}

Managing Director
Tricor Pacific Capital, Inc.
West Vancouver, British Columbia

HUGH C. MORRIS^{1,3}

Chairman
Eldorado Gold Corporation
Delta, British Columbia

DAVID J. ROWNTREE^{2,3}

Managing Director
Tricor Pacific Capital, Inc.
West Vancouver, British Columbia

RODERICK R. SENFT⁴

Managing Director
Tricor Pacific Capital, Inc.
West Vancouver, British Columbia

DAVID G. UNRUH^{3,5}

Vice Chairman
Duke Energy Gas Transmission (Canada)
West Vancouver, British Columbia

ARTHUR H. WILLMS^{2,4,5}

Director
Westcoast Energy Inc. and Union Gas Ltd.
Vancouver, British Columbia

- 1 Audit Committee
- 2 Human Resources and Compensation Committee
- 3 Environment, Health and Safety Committee
- 4 Executive Committee
- 5 Corporate Governance Committee

OFFICERS

R.F. CHASE

Chair of the Board

R.G. DYCE

President and Chief Executive Officer

G.B. WEERES

Vice President, Operations and Engineering

E.A. FLETCHER

Chief Financial Officer

C.P. DONOHUE

Director, Regulatory Affairs & Gas Supply

K. STARK-ANDERSON

Secretary

C.P. DONOHUE

Assistant Secretary

REGISTRAR & TRANSFER AGENT

COMPUTERSHARE TRUST COMPANY OF CANADA

Vancouver, Calgary, Regina, Winnipeg,
Toronto, Montreal

AUDITORS

DELOITTE & TOUCHE LLP

Vancouver, British Columbia

ANNUAL MEETING

The Annual Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held at the Hyatt Regency Vancouver Hotel, 655 Burrard Street, Grouse Room, Vancouver, British Columbia on April 22, 2004 at 10:30am local time.



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